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Control of Utility Boiler and Gas Turbine
Pollutant Emissions by Combustion Modification--
Phase II

Exxon Research and Engineering Co.
Florham Park, NJ

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

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CONTROL OF UTILITY BOILER AND
GAS TURBINE POLLUTANT EMISSIONS
BY COMBUSTION MODIFICATION--PHASE II

Prepared for

Office of Air Quality Planning and Standards

Prepared by

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

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July 1981

**CONTROL OF UTILITY BOILER
GAS TURBINE POLLUTANT EMISSIONS BY COMBUSTION
MODIFICATION - PHASE II**

BY:

E. H. MANNY AND A. R. CRAWFORD

**EXXON RESEARCH AND ENGINEERING COMPANY
P. O. BOX 101
FLORHAM PARK, NEW JERSEY 07932**

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EPA PROJECT OFFICER: ROBERT E. HALL

**INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
Office of Environmental Engineering and Technology
RESEARCH TRIANGLE PARK, N.C. 27711**

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ABSTRACT

The report gives results of the second phase of a field study to assess the applicability of combustion modification techniques to control NO_x and other pollutant emissions from utility boilers and gas turbines without causing deleterious side effects. Comprehensive, statistically designed tests were used to evaluate the effect of combustion modifications. The most extensively studied combustion modification for utility boiler applications was staged firing at low excess air, which can reduce NO_x emissions by up to about 50%, based on the results of short term tests. Tests of B and W's Low NO_x, dual register burner were also included. With emphasis on NO_x emission control for coal-fired utility boilers, special attention was paid to the determination of potentially adverse side effects: increased combustible emissions, unwanted changes in particulate mass loading and size distribution, reduced boiler efficiency, increased furnace slagging and tube wall corrosion. Short term tests indicate that staged combustion may be applied to coal-fired utility boilers. The extent of furnace tube wall corrosion and slagging could not be determined conclusively, based on the results of short term (300-hour) corrosion probing runs under low NO_x and baseline operating conditions. It was found however that corrosion probes exposed for longer periods (300 to 1000 hours) may more effectively correlate with actual furnace tube corrosion rates. Extensive long-term corrosion testing is necessary to verify these observations. For this reason, a long term furnace tube wall corrosion test of about 18 months duration was conducted on a 500 MWe front-wall fired boiler at Gulf Power Company's Crist Station.

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SUMMARY

This report covers Phase II of a two-phase field test program. The detailed results of Phase I were reported in Report No. EPA-600/7-78-036a dated March, 1978. This report presents detailed results and discussion of the seven utility units tested under Phase II and summarizes the conclusions reached from the entire program. A separate report will be published on a comprehensive, long-term corrosion study performed on Gulf Power Company's Crist No. 7 Boiler. Phase I of this field test program was jointly sponsored by EPA (Contract No. 68-02-1415) and EPRI (Project No. 200) and the entire study was conducted with the cooperation of utility operators and equipment manufacturers. Exxon Research and Engineering Company's mobile sampling/analytical van was used to obtain measurements of gaseous emissions, particulate mass, particulate size distribution, furnace tube wall corrosion, and boiler efficiency.

This program has placed major emphasis upon NO_x emission control through combustion modification of coal-fired boilers. In addition, field tests of an oil fired boiler, mixed fuel-fired boilers, and gas turbines have been conducted.

In Phase II, four coal-fired utility boilers, an oil-fired utility boiler, and two utility sized gas turbines were tested. Thus, in the entire program (Phase I and Phase II), eleven coal-fired boilers, including two with mixed-fuel firing (coal-oil; coal-gas) capabilities, an oil fired boiler and three gas turbines (two with water injection capability) were tested.

Among the eleven coal-fired boilers tested, five were equipped with special NO_x emission reduction equipment. Three of the Combustion Engineering designed boilers tested have overfire air ports. A Babcock and Wilcox designed boiler has been retrofitted with that company's "low NO_x " dual register burners. A second Babcock and Wilcox boiler was equipped with overfire air ports, compartmentalized windbox and conventional, circular register burners. A Foster Wheeler boiler designed to operate with a wet bottom at low loads was also tested for possible side effects under "low NO_x " operation. Two of the three General Electric gas turbines were equipped with water injection capabilities for gas and oil firing. The three-phase test programs conducted on most of these units consisted of, first, a statistically designed short period test program to determine baseline and minimum NO_x emission capability of the unit, second, a one or two day sustained run under "low NO_x " operation to determine if potential operating problems arise and third 300-hour sustained runs under baseline and "low NO_x " conditions to check on other potential adverse side effects such as increased corrosion and slagging problems, loss in boiler efficiency and changes in particulate emissions.

Several key findings were determined from an analysis of the gaseous emission data. The B&W boiler retrofitted with the new burners emitted 29% less NO_x under normal firing (389 vs 278 ppm) and over 50% under full load, staged firing operation (600 vs 278 ppm) than was emitted from an identical boiler equipped with conventional burners. The B&W boiler equipped with overfire air ports emitted 62% less NO_x than under baseline operation (726 ppm vs 278 ppm). Tangentially fired boilers equipped with overfire air ports emitted about 20% less NO_x than similar

boilers when tested under normal firing operation. Modified firing using overfire air ports and low excess air resulted in an average of over 40% additional reduction in NO_x emissions at full load, for a reduction of more than 50% over boilers not equipped with overfire air ports. Mixed fuel-fired boiler NO_x emission levels increased as the percent of coal in the coal-oil or coal-gas mixture increased, but not linearly. A gas-fired gas turbine emitted 84% less NO_x , and an oil-fired gas turbine emitted 90% less NO_x when operating with full water injection capabilities, compared to normal operation at full load.

Only relatively minor differences have been observed in particulate mass loadings between "low NO_x " and baseline firing conditions. Unburned carbon in the fly-ash, which was observed to increase in previous studies (especially on front wall and horizontally opposed fired boilers) was found to decrease on some of the boilers tested in this program. Particle size distribution, which could affect electrostatic precipitator collection efficiency, was found to be very similar for "low NO_x " operation and for baseline conditions. As in previous studies, no major changes in boiler efficiency have been observed as a result of "low NO_x " operation.

In 300-hour sustained runs, no major differences in corrosion rates of corrosion coupons have been observed for low NO_x firing compared to normal operation. However, long term tests measuring actual furnace wall tube wastage are needed to settle this important question. A report will be published on the experience from one wall-fired boiler (Gulf Power's Crist No. 7) where a comprehensive long-term corrosion test program was conducted with Foster Wheeler Energy Corporation.

1. INTRODUCTION

Since 1970, Exxon Research and Engineering Company (ER&E) has been conducting field studies under EPA sponsorship on the application of combustion modification techniques to control pollutant emissions from utility boilers. The emphasis in these studies has been on controlling NO_x emissions without causing adverse side-effects.

Under EPA Contract No. CPA 70-90 (1), significant reductions of NO_x were achieved for gas and oil-fired boilers using combustion modification techniques in field testing of limited duration, without attempting to optimize the technology. The principal modifications investigated consisted of minimizing excess air, staged introduction of the combustion air, flue gas recirculation, varying boiler load, and varying air preheat temperature. Also, as part of that study, it was possible to achieve significant reductions in NO_x emissions for two of the seven coal-fired boilers tested, through the combination of low excess air with staged firing.

Because of the difficulty of controlling NO_x emissions from coal-fired boilers, in the subsequent EPA-sponsored ER&E study (Contract No. 68-02-0227) (2) the emphasis shifted to a more detailed investigation of emission control for coal-fired utility boilers, again in cooperation with boiler owner-operators and manufacturers. These field studies, on twelve coal-fired units representative of the current design practices of the major U.S. boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler, and Riley-Stoker), have produced very promising results. It was possible to achieve reductions in NO_x emissions ranging between about 30% and 50%, without apparent adverse side-effects. In addition to gaseous emissions measurements, the studies included particulate mass loading and unburned combustible measurements, accelerated furnace corrosion probing, determination of boiler efficiency, and observations on changes in boiler operability with particular attention to slagging, fouling, and flame problems.

Based on the encouraging results of the above work, the Environmental Protection Agency and the Electric Power Research Institute decided to jointly fund the present ER&E field study (Contract 68-02-1415). The scope of work was broadened to determine the effects of combustion modification techniques on the control of pollutant emissions and on the performance of fossil fuel fired power generation equipment. In this field program, the combustion equipment selected for study included coal-fired, oil-fired and mixed-fuel fired boilers to be studied, in addition to short-term tests on stationary gas turbines. The principal continuing emphasis in this work remained on coal-fired utility boilers. All but one of the coal-fired boilers tested in this study had dry-bottom furnaces. Phase I results are available in Report No. EPA-600/7-78-036a dated March, 1978 (3). This report covers detailed results from Phase II of the study and summarizes the conclusions from both Phases.

In the field studies detailed in this report, the combustion equipment selected was tested in cooperation with the owner-operators and the manufacturers. The effectiveness of equipment modifications designed to provide NO_x emission control, such as coal-fired boilers constructed with overfire air ports, and the use of low NO_x emitting improved burner design were explored as well as the use of water injection in gas and oil-fired, utility sized gas turbines. Potential adverse side-effects of combustion modifications were studied in more detail than previously. Thus, in addition to the gaseous emission measurements (including pollutants, stable combustion products and unburned combustibles), particulate mass and size distribution measurements were made under both normal and low NO_x modes of boiler operation.

As in the earlier field studies, the effect of combustion modifications on boiler efficiency and operability was determined. Special attention was paid to the demonstration of potential furnace fireside tube wall corrosion problems that may result from staged firing with coal, i.e., with parts of the boiler operated under fuel rich, reducing conditions. For this purpose, 300-hour corrosion probe runs with air-cooled coupons were made under both low NO_x and baseline firing conditions in the boilers studied.

Under Contract No. 68-02-1415 a separate Data Supplement, containing detailed raw pollutant emission and operating data covering all units tested in Phases I and II, will be issued following completion of this program. In addition, a Guideline publication has been issued for utility operators, as report No. EPA-600/8-80-27. Furthermore, a report will be issued which will describe results of a comprehensive, long-term fireside tube wall corrosion study on Gulf Power Company's Crist No. 7 Boiler while operating under baseline and low NO_x conditions.

2. FIELD STUDY PLANNING AND PROCEDURES

This section discusses the major steps involved in field study planning and the testing methods used to obtain emission, corrosion and performance measurements. Field study planning steps included selection of representative power generation equipment (with participation of EPA, EPRI, equipment manufacturers and equipment operators) and designing an effective test program strategy. Methods of gaseous emission testing were similar to those developed and applied in ER&E's "Systematic Field Study" (1). Particulate sampling, corrosion probing and performance measurements were also based on methods used in ER&E's previous field studies (2). Boilers firing coal, oil, coal-oil and coal-gas mixed fuel were tested, as were two oil-fired and one gas-fired power generating gas turbines.

2.1 SELECTION OF POWER GENERATION COMBUSTION EQUIPMENT

This report covers the detailed results from field tests completed on four coal-fired boilers, an oil-fired boiler, an oil-fired gas turbine and a gas-fired gas turbine. Summary tables of the results from Phase I of this program are also included for comparison and summary purposes. A separate report will be prepared covering the comprehensive, long term corrosion test program conducted with Foster Wheeler Energy Corporation on Gulf Power's Crist No. 7 Boiler.

The successful selection of boilers representing current design practices was the result of a cooperative planning effort by Exxon Research, EPA, EPRI and boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler and Riley Stoker). The process of developing boiler selection criteria, reviewing boiler manufacturers' candidate boilers meeting the criteria, selecting a tentative list of boilers for detailed field meetings and final selection and scheduling of test programs was described in a previous report (2).

Design factors were the prime consideration in selecting boilers in the current field test program after other criteria such as size, operating flexibility, boiler measurement and control capability had been met. Boilers representing the current design practices of all four utility boiler manufacturers were sought for this study. Coal-fired boilers equipped with overfire air ports or with new burners installed for NO_x emission control were of special importance to compare the emission control performance of such units to those operated under modified conditions but without making the NO_x control capability an integral feature of the equipment. In Phase I of this program the cooperation of boiler operators was secured to

test three tangentially fired (2 coal, 1 coal-gas mixed fuel) boilers with overfire air ports and a wall fired boiler retrofitted with special low NO_x burners. In Phase II, a cooperative test program was conducted on a horizontally opposed, coal-fired boiler equipped with overfire air ports, and two, large gas turbines equipped with water injection capabilities for NO_x emission control. Field testing of a presently operating front-wall, coal-fired utility boiler equipped with overfire air ports was attempted but could not be arranged with its owner-operator.

The design and operating features of the seven utility units tested in Phase II of this program are summarized in Table 2-1. Four of the boilers fired pulverized coal, including a front wall, a horizontally opposed and a tangentially fired unit. The fifth boiler tested is a horizontally opposed, oil-fired unit with flue gas recirculation into the furnace for steam temperature control. We were fortunate in obtaining the cooperation of Houston Lighting and Power Company, (operator) and General Electric Company, (manufacturer) in testing two large (50 MWe) modern gas and oil fired gas turbines with water injection capability.

The design and operating features of the seven coal or mixed-fuel fired boilers tested in Phase I of the current program are summarized in Table 2-2. Four of these boilers are tangentially fired (ranging in size from 130 MWe to 800 MWe) and three of them are wall fired (a rear wall fired 125 MWe unit, a front wall fired, 290 MWe unit, and a horizontally opposed fired 270 MWe capacity unit). As discussed earlier, these boilers were selected for field studies at the recommendation of their respective manufacturers as representatives of current design practices and/or because of specially designed NO_x reduction capabilities. Tables 2-3 and 2-4 present summaries of coal and oil-fired boilers tested in a previous program (2) for comparison purposes.

2.2 TEST PROGRAM STRATEGY

The up-to-date, comprehensive information obtained in field meetings provided the necessary data to develop detailed, run-by-run proposed test program plans for review by the sponsors and the cooperating parties. Each test program, tailored to take full advantage of the particular combustion control flexibility of each boiler, was comprised of three phases: (1) short test-period runs, (2) a 1-3 day sustained "low NO_x" run, and (3) 300-hour sustained "low NO_x" and normal operation runs. Thus, the strategy used for field testing coal-fired boilers consisted of first, defining the optimum operating conditions for NO_x emission control, without apparent adverse side-effects in short-term statistically designed test programs. Second, the boiler was operated for 1-3 days under the "low NO_x" conditions determined during the optimization phase, for assessing boiler operability problems. Finally, where possible, sustained 300-hour runs were made under both baseline and modified ("low NO_x") operating conditions. During this period, air-cooled carbon steel coupons were exposed as corrosion probes in the vicinity of furnace water tubes, to determine through accelerated corrosion tests whether operating the boiler under the reducing

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TABLE 2-1
SUMMARY OF UTILITY UNITS TESTED DURING PHASE II

Station and Boiler No.	Boiler Operator	Boiler Mfr. (a)	Type of Firing (b)	Fuel Burned	MCR (Mile)	No. of Burners	Test Variables	No. of Test Runs	NO _x Emissions		
									Baseline ppm (lb/10 ⁶ BTU) (h)	Low NO _x ppm (lb/10 ⁶ BTU) (h)	% NO _x (a) Reduction
1. East Kentucky Power Cooperative, Inc.	Cooper - 2	B&W	FW	Coal	220	18	4	101 (c)(d)	557 (0.76)	433 (0.59)	22
2. Public Service Company of Colorado	Comanche - 2	B&W	HO(e)	Coal	350	32	3	18 (c)	726 (1.00)	278 (0.36)	62
3. Public Service Electric and Gas Company	Sewaren - 5	B&W	HO	Oil	330	24	5	24	311 (0.40)	211 (0.27)	32
4. Louisville Electric and Gas Company	Mill Creek - 1	CE	T	Coal	330	20		(c)	533 (0.71)	(1)	--
5. Gulf Power Company	Crist - 7	FMEC	HO	Coal	500	24	4	29(c)	827 (1.10)	570 (0.760)	31
6. Houston Lighting and Power Company	Wharton - 43 (Gas Turbine)	GE	(f)	Gas	50	--	2	16	212 (0.29)	34 (0.044)	84
7. Houston Lighting and Power Company	Wharton - 42 (Gas Turbine)	GE	(f)	Oil	50	--	2	13	382 (0.45)	40 (0.048)	90
Average of Coal Fired Boilers									50	661 (0.86)	427 (0.58)

(a) B&W - Babcock and Wilcox, GE - General Electric, CE - Combustion Engineering; FMEC - Foster Wheeler Energy Corporation

(b) FW - Front Wall, HO - Horizontally Opposed, T - Tangential

(c) Particulate tests performed on these boilers

(d) Corrosion probe tests performed on this boiler

(e) Overfire air ports

(f) Water injection

(g) % NO_x reduction of full or near full load

(h) PPM NO_x - 3% O₂, dry basis

(i) Additive test at baseline condition only

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TABLE 2-2
SUMMARY OF COAL AND MIXED FUEL FIRED BOILERS TESTED DURING PHASE I

Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	Fuel(c) Burned	MCR (Mw)	No. of Burners	Test Variables	No. of Test Runs	Baseline ppm (lb/10 ⁶ BTU) (1)	NO _x Emissions Low NO _x ppm (lb/10 ⁶ BTU)	% NO _x (h) Reduction
1. Tennessee Valley Authority	Widows Creek - 5	B&W	BW	C	125	16	4	31(d)	597 (0.81)	468 (0.64)	22
2. Southern Electric Generating Company	E. C. Gaston - 1	B&W	HO(e)	C	270	18	5	37(d)	389 (0.53)	278 (0.38)	29
3. Alabama Power Company	Barry - 2	CE	T(f)	CG	130	16	6	38	341 (0.46)	189 (0.26)	45
4. Potomac Electric Power Company	Morgantown - 1	CE	T	CO	575	40	5	27	552 (0.75)	403 (0.55)	27
5. Salt River Project	Navejo - 2	CE	T(f)	C	800	56	4	36(d)	492 (0.67)	282 (0.38)	43
6. Public Service Company of Colorado	Comanche - 1	CE	T(f)	C	350	20	4	30(d)	417 (0.57)	261 (0.35)	37
7. Public Service Electric and Gas Company	Mercer - 1	FW	FW(g)	C	270	24	4	33(d)	1383 (1.88)	876 (1.19)	37
Average of Coal Fired Boilers								33	656 (0.89)	433 (0.59)	34

(a) B&W - Babcock and Wilcox, CE - Combustion Engineering, FW - Foster Wheeler

(b) BW - rear wall, HO - horizontally opposed, T - tangential, FW - front wall

(c) C - coal, C-G - coal-gas mixed, C-O - coal-oil mixed

(d) Particulate and corrosion probe tests performed on these boilers

(e) Special low NO_x emission burners

(f) Overfire air ports

(g) Wet bottom furnace

(h) % NO_x reduction at full or near full load

(i) PPM NO_x - 3% O₂, dry basis

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TABLE 2-3
SUMMARY OF COAL-FIRED BOILERS TESTED IN A PREVIOUS EXXON/EPA FIELD TEST PROGRAM (2)

	Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	MCR (Mc)	No. of Burners	Test Variables	No. of Test Runs	NO _x Emissions		
									Baseline ppm (lb/10 ⁶ BTU) (f)	Low NO _x ppm (lb/10 ⁶ BTU) (g)	% NO _x (e) Reduction
1.	Tennessee Valley Authority	Widows Creek - 6	B&W	RW	125	16	4	41(c)	634 (0.84)	379 (0.50)	40
2.	Gulf Power	Crist - 6	F-W	PW	320	16	4	22(c)	832 (1.11)	550 (0.73)	34
3.	Georgia Power	Harlee Branch - 3	B&W	HO	480	40	4	51(c)(d)	711 (0.95)	463 (0.62)	35
4.	Arizona Public Service	Four Corners - 4	B&W	HO	800	54	5	26(c)(d)	935 (1.24)	488 (0.65)	48
5.	Utah Power and Light	Naughton - 3	CE	T	330	20	6	26(c)(d)	531 (0.71)	219 (0.29)	59
6.	Alabama Power	Barry - 4	CE	T	350	20	7	46(c)(d)	415 (0.55)	273 (0.36)	34
7.	Alabama Power	Barry - 3	CE	T	250	48	4	8	410 (0.55)	310 (0.41)	24
8.	Tampa Electric	Big Bend - 2	RS	Turbo	350	24	4	14	600 (0.80)	398 (0.53)	34
9.	Central Illinois Light	E. D. Edwards - 2	RS	PW	256	16	4	19	703 (0.93)	359 (0.48)	49
10.	Basin Electric	Leland Olds - 1	B&W	HO	218	20	3	13	569 (0.76)	375 (0.50)	33
11.	Pacific Power and Light	Dave Johnston - 2	B&W	PW	105	18	3	14	454 (0.60)	214 (0.28)	53
12.	Pacific Power and Light	Dave Johnston - 4	CE	T	348	28	7	6	434 (0.53)	384 (0.51)	12
Average of Coal Fired Boilers									602 (0.80)	368 (0.49)	39

(a) B&W - Babcock and Wilcox
CE - Combustion Engineering
F-W - Foster Wheeler Energy
RS - Riley Stoker
(b) RW - Rear Wall
PW - Front Wall
HO - Horizontally Opposed
T - Tangential
Turbo - Turbo-Furnace

(c) Particulate tests performed on these boilers
(d) Corrosion probe tests performed on these units
(e) % NO_x reduction at full or near full load
(f) PPM NO_x - 3% O₂, dry basis

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TABLE 2-4
SUMMARY OF OIL-FIRED BOILERS TESTED IN A PREVIOUS EXXON/EPA FIELD PROGRAM (2)

Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	MCR (MWe)	No. of Burners	Test Variables	No. of Test Runs	NO _x Emissions		
							Baseline ppm (lb/10 ⁶ BTU) (c)	Low NO _x ppm (lb/10 ⁶ BTU) (c)	Σ NO _x (d) Reduction
1. Atlantic City Electric Deepwater - 3	B&W	FW	55	6	2	8	142 (0.19)	118 (0.16)	17
2. Atlantic City Electric Deepwater - 5	B&W	FW	55	6	2	4	221 (0.29)	175 (0.23)	21
3. Atlantic City Electric Deepwater - 8	B&W	FW	83	16	3	25	246 (0.33)	124 (0.16)	50
4. Atlantic City Electric Deepwater - 9	CE	T	23	6	2	7	286 (0.38)	101 (0.13)	65
5. Atlantic City Electric B. L. England - 1	B&W	Cy	136	3	2	7	441 (0.59)	313 (0.42)	29
6. Atlantic City Electric B. L. England - 2	B&W	Cy	168	4	1	2	361 (0.48)	303 (0.42)	16
Average of Oil-Fired Boilers							283 (0.37)	189 (0.25)	33

(a) B&W - Babcock and Wilcox, CE - Combustion Engineering

(b) FW - front wall, T - tangential, Cy - cyclone

(c) PPM NO_x - 3% O₂, dry basis

(d) Σ NO_x reduction at full or near full load

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conditions associated with staged firing results in increased furnace tube wall corrosion rates. Particulate samples were obtained under both baseline and "low NO_x" conditions. Engineering information on boiler operability, such as flame instability, impingement and slagging problems, and data on boiler performance were obtained.

Statistical principles (as discussed in more detail in a previous report (1)) provided practical guidance in planning the Phase I test programs, e.g., how many, and which test runs to conduct, as well as the proper sequence in which they should be run. These procedures allow valid conclusions to be drawn from analysis of data on only a small fraction of the total possible number of different test runs that could be made in principle, resulting in increased productivity of the research work. Our earlier studies (2) describe in detail an example of these principles applied to field testing of a wall-fired boiler.

Statistical principles were also used extensively in the analysis of emission data recorded from each test run. For example, least squares regression analysis was used to obtain valid estimates of the relationship between NO_x emission levels and operating variables, such as excess air level or water injection level. These techniques provide objective, uniform methods of analysis that can be easily verified, provide the basis for efficient assessment of outlier data, and limit the risk of drawing false conclusions.

3. RESULTS AND DISCUSSIONS

The field test results obtained on the individual boilers investigated under a variety of operating conditions in Phase II of this study are presented in four parts. These parts are, respectively, gaseous emission measurements, flue gas particulate mass loadings and size distributions measured upstream of particulate collector equipment, corrosion probing data obtained in accelerated external furnace tube corrosion tests, and boiler efficiency calculated by the heat loss method. Gaseous emission data and most of the particulate emission data were obtained under normal, as well as modified firing operation. As discussed before, particulate loadings of the flue gas were determined only under conditions corresponding to baseline and low NO_x operation, for purposes of comparison of the relative effect of modified combustion operation on flue gas particulate mass loadings and size distribution in coal combustion. Similarly, the sustained 300-hour corrosion probing tests were conducted to determine relative differences in corrosion rates under baseline and modified combustion modes. It was recognized that short term corrosion probing tests cannot substitute for long term tests in which actual furnace tube wastage is determined. Thus, the measurements in the current studies were made to detect major differences with the anticipation that confirmation of these findings will have to be based on more extensive long term corrosion tests.

The gaseous emission data obtained under baseline and modified firing conditions at various load levels are presented first. Throughout this report, NO_x concentrations are expressed as ppm, adjusted to three percent O_2 in the flue gas, on a dry basis unless specified otherwise (such as ppm, adjusted to 15% O_2 , dry basis for gas turbine emissions).

In addition to the results obtained in testing coal-fired boilers, this section also presents the gaseous emission data on an oil-fired boiler, and two gas turbines used for power generation. The gas turbine tests, as discussed earlier, were run to broaden the available data base on emissions from power generation combustion equipment and to obtain data on gaseous emissions under water injection operation for both gas and oil-fired units.

3.1 GASEOUS EMISSION RESULTS

Test programs were conducted on four coal-fired boilers consisting of a front-wall fired, an opposed-wall fired and a tangentially fired boiler. Field tests were also conducted on two gas turbines, one fired gas and the other fired oil. The horizontally opposed-wall-fired boiler is equipped with overfire air ports and compartmentalized windboxes. Both gas turbines were equipped with water injection for NO_x emission control. Table 2-1 lists each utility unit by station and number, manufacturer, type of firing, fuels burned, full load MWe rating, and number of burners. In addition, the number of operating test variables included in each test program and the number of test runs completed are also shown in Table 2-1.

In presenting the results and discussion on the field tests for each of these power generation combustion equipment types, the unit will

be briefly described. First, the reasons for its selection will be discussed; second, the key operating variables tested (load, excess air level, staged firing patterns, etc.) will be summarized and the resulting NO_x and other emission data will be given for each test run according to the experimental test design used; and third, these results will be presented in graphical form. Major conclusions and overall findings of this program will be presented in Section 4 of this report. Summary tables containing operating and emission data from each test run for each boiler tested are presented in Appendix B. A separate data supplement report will be available for those interested in detailed raw data.

3.1.1 John Sherman Cooper Station, Boiler No. 2 East Kentucky Power Cooperative, Inc.

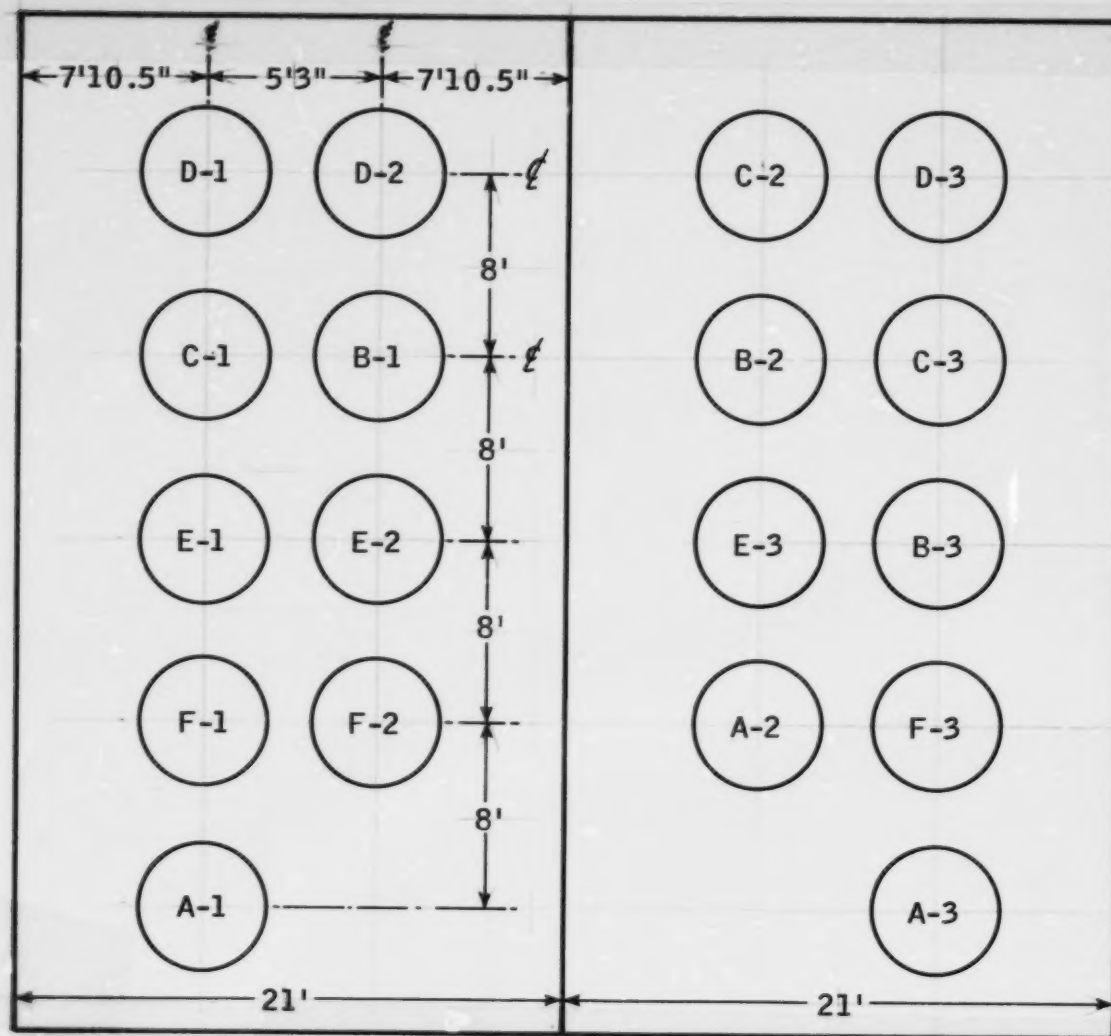
Cooper No. 2 unit was selected for testing for two reasons. First, it served as an excellent candidate for a single wall-fired boiler, long-term corrosion test program similar to the comprehensive test program that Exxon Research has conducted with Foster Wheeler Energy Corporation on Gulf Power Company's Crist No. 7 unit. Second, this boiler had the operating flexibility, fuel characteristics and potential NO_x emission reduction capability to meet current program objectives.

Cooper No. 2 unit is a front-wall fired Babcock and Wilcox designed boiler rated at 220 MWe (gross load) and 703,000 kg/hr (1,550,000 lbs/hour) steam flow. Six Babcock and Wilcox Type EL pulverizers (using the ball bearing principle for grinding) feed 18 burners arranged in five rows as shown in Figure 3-1. The furnace has a width of 12.8 m (42 feet) and measures 7.32 m (24 feet) from front wall to rear wall. Heating surface measurements in square meters (square feet) are: boiler 386 (4,153), furnace 1983 (21,350), primary superheater 6,371 (68,575) secondary superheater 665 (7,157), reheat superheater 2709 (29,158) and economizer 2,718 (29,258). Superheat steam outlet temperature is 813 K (1005°F) at 13.1 MPa (1890 PSIG) pressure. Reheat outlet temperature is 814 K (1005°F) at 3.17 MPa (445 PSIG) pressure.

The coal proximate analysis used in boiler design was 8% moisture, 33% volatile matter and 4.5% fixed carbon. Ultimate analysis components were 12.5% ash, 4.5% sulfur, 4.2% hydrogen, 63.5% carbon and 1.2% nitrogen.

3.1.1.1 Discussion of Gaseous Emission Results

Table 1 in Appendix B contains a summary of the operating conditions and flue gas measurements for the 101 gaseous test runs completed on Cooper No. 2 unit. The key operating variables listed are gross load (MWe), firing pattern, secondary air register settings (% open) and excess air level (high, normal and low). Low excess air operation was defined as the minimum excess air level that resulted in a maximum concentration of 200 ppm CO from any single sampling location. Tables 3-1 and 3-2 present a summary of test results (test run number, % oxygen and ppm NO_x) arranged according to the statistical test program design.



Front Wall of Furnace

Figure 3-1. Mill-burner configuration (Cooper No. 2 unit).

Figures 3-2, 3-3, 3-4 and 3-5 are plots of ppm NO_x vs. average % oxygen in the flue gas for operating loads (MWe) of 200 to 227, 165 to 199, 135 to 160 and 90 to 130 MWe, respectively. Least squares, linear regression lines have been drawn through the data representing the various firing patterns tested. We will discuss the analysis and conclusions obtained from each of the four load levels and then discuss the potential operating problems and limitations that occur with combustion modification on this boiler.

Cooper No. 2 unit operated at 200 to 227 MWe produced a baseline NO_x emission level of 557 ppm at 3.1% O₂ (or 575 ppm at 3.6% O₂). This relatively low baseline NO_x level can be attributed to the use of a heat absorbing division wall in the furnace, the relatively low heat release per burner (about 60% of Crist No. 7 unit), wide burner spacing and relatively generous sized furnace. Operating with low excess air (2.2% O₂ in flue gas) reduced NO_x emissions by 8% to 511 ppm. Low excess air (2.6% O₂), staged firing pattern S₂, ("D" mill fired lean, at about ½ normal coal feed rate) reduced NO_x emissions by an average of 13% from baseline to 483 ppm. Test run No. 6, conducted under S₂ operation at 2.1% O₂, produced NO_x emissions of only 433 ppm or 22% less than baseline operation.

Reducing load to the 165 to 199 MWe range provided sufficient operating flexibility that six staged firing operations could be tested in addition to baseline firing with all burners firing coal. Figure 3-3 is a plot of ppm NO_x vs. % oxygen in the flue gas for the 37 test runs conducted within this load range. Least squares, linear regression lines have been plotted on Figure 3-3 through the data representing these firing patterns. In addition to firing patterns, S₁-baseline, and S₂-("D" mill lean, individual burners were operated on air only (S₃-D₁ and C₁ and S₆-D₁, C₂ and B₁ burners on air only) and upper mills were operated lean or on air only (S₄-("C" and "D" mills lean, S₅-("D" mill on air only and S₉-("C" mill on air only).

Analysis of the data obtained from test runs conducted at 165 to 199 MWe lead to the following conclusions (see Table 3-1 and Figure 3-3):

- Excess air level, as expected, had a highly significant effect on NO_x emission levels as shown by the slope of the least squares lines on Figure 3-3. Average reduction of NO_x emission for a 1% decrease in flue gas O₂ content were 66, 40, 69, 68 and 69 ppm for S₁, S₂ S₃ (+ S₄ and S₆), S₅ and S₉ firing patterns.
- Baseline operation NO_x emissions were 592 ppm vs. 557 ppm at full load. This increase was partly due to higher excess air operation (3.4% vs. 3.1% O₂) and partly due to maintaining high coal feed on the top mills for steam temperature control.
- Low excess air, staged firing pattern S₅, "D" mill on air only, produced the lowest NO_x emission level (350 ppm at 2.6% O₂) of the six staged firing patterns tested. This amounted to a 41% reduction from baseline emissions. Staging patterns S₃, S₄ and S₆ produced similar NO_x emission levels when adjusted for excess air level; consequently, a single regression line was calculated for the six test runs conducted using those firing patterns. All of the firing patterns tested were capable of reducing NO_x emission levels below the Federal NSPS level of 0.7 lb NO_x/10⁶ BTU (515 ppm). The choice of which to use would depend upon operating considerations as discussed later in Section 3.1.1.2.

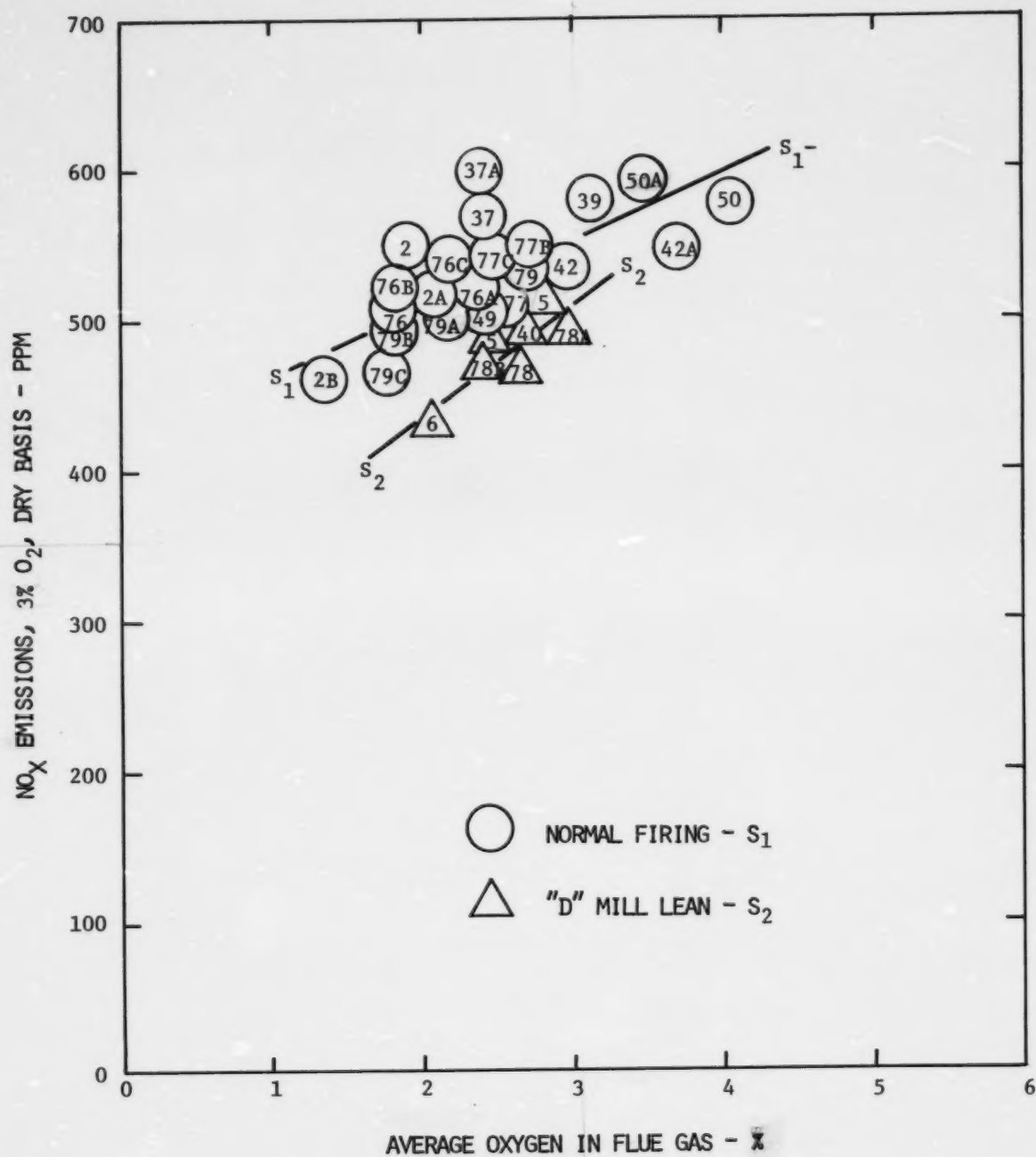


Figure 3-2. NO_x emissions vs % O₂ in flue gas for Cooper No. 2 boiler operated at 200 to 227 MW_e.

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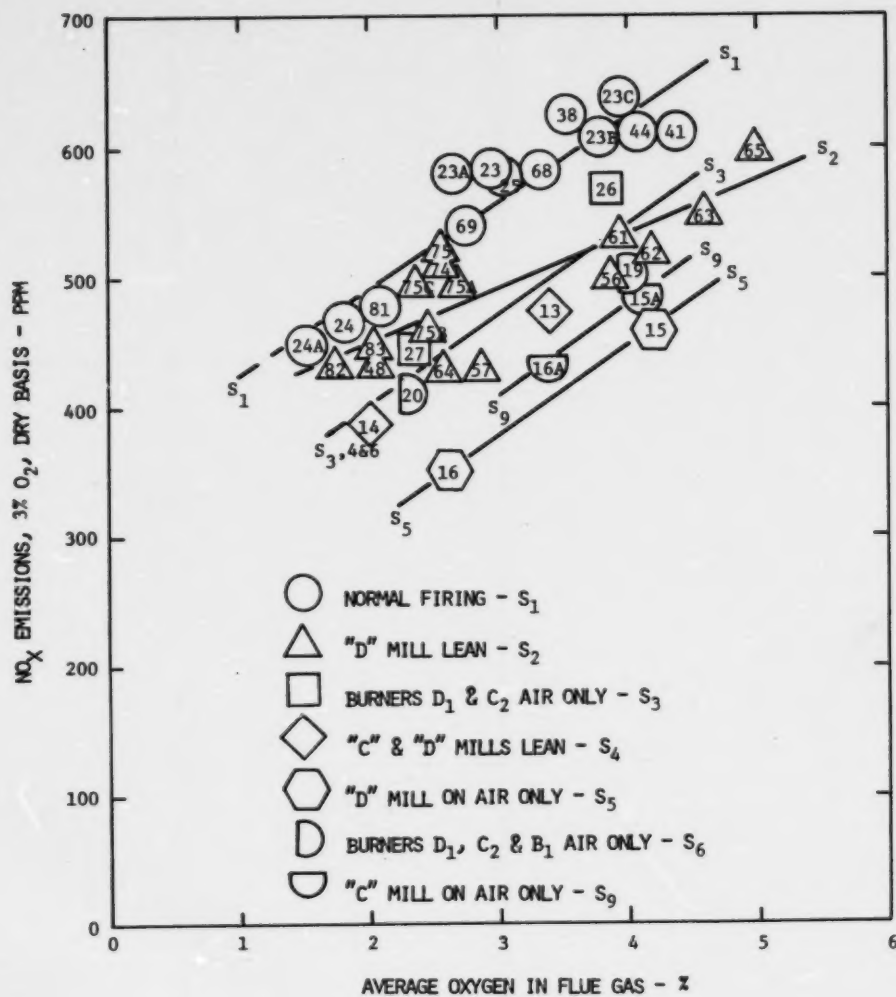


Figure 3-3. NO_x emissions vs % O₂ in flue gas
for Cooper No. 2 boiler operated at 165 to 200 MW_e.

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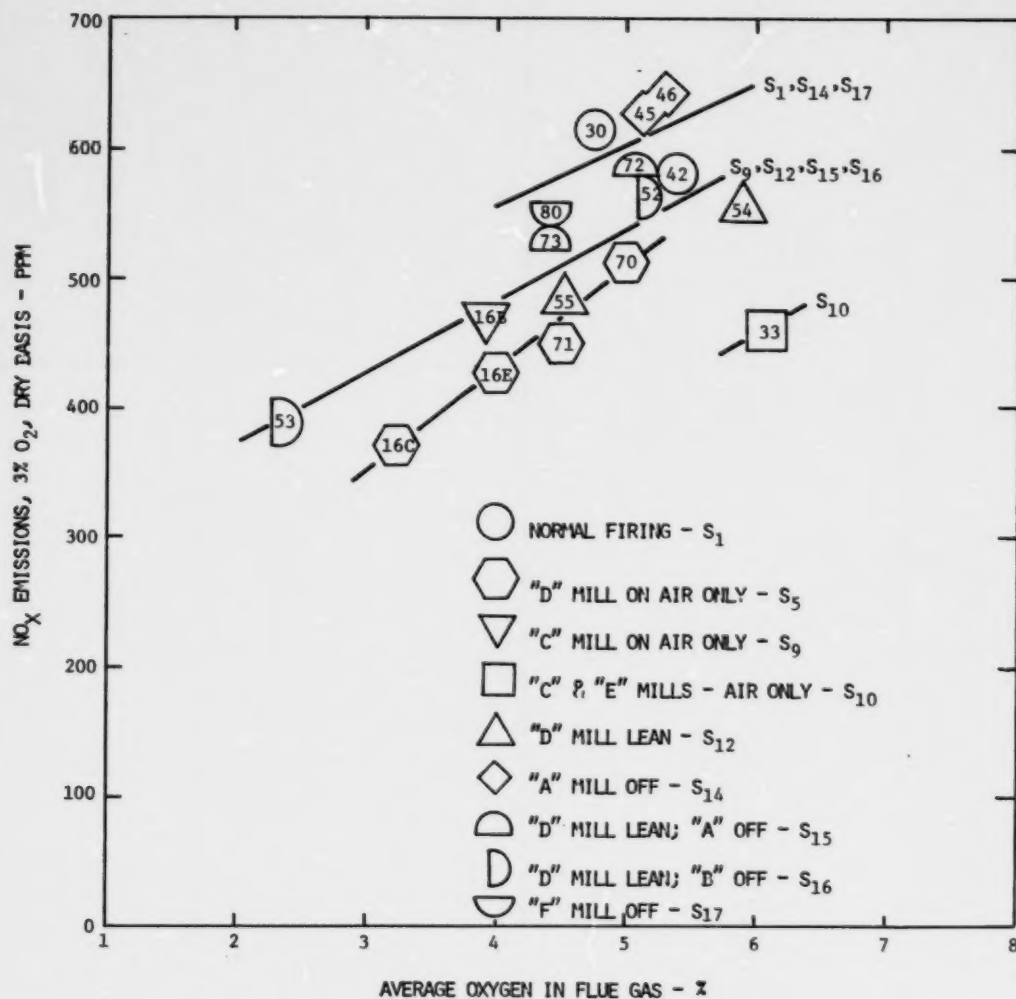


Figure 3-4. NO_x emissions vs % O₂ in flue gas for Cooper No. 2 boiler operated at 135 to 160 MW.

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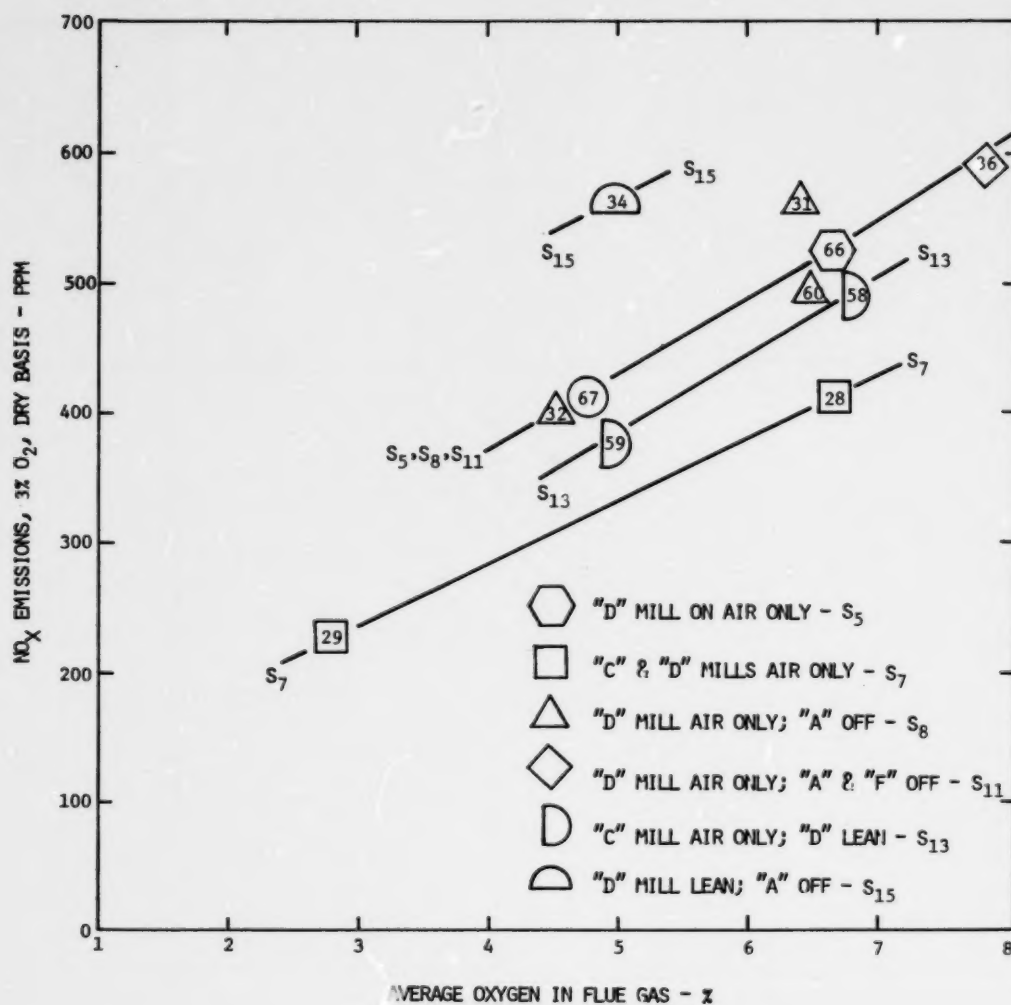


Figure 3-5. NO_x emissions vs % O₂ in flue gas for Cooper No. 2 boiler operated at 90 to 130 MW_e.

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TABLE 3-1

TEST PROGRAM DESIGN - COOPER NO. 2 UNIT (165 TO 227 MWe)
(TEST RUN NO., % OXYGEN AND PPM NO. % (3% O₂, DRY BASIS)

	L ₁ - 200 to 227 MWe		L ₂ - 165 to 199 MWe	
	A ₁ -Normal Excess Air	A ₂ -Low Excess Air	A ₁ -Normal Excess Air	A ₂ -Low Excess Air
S ₁ -All Burners Firing Coal	(37) 2.5-568 (37A) 2.5-587 (39) 3.2-578 (42) 2.9-521 (42A) 3.6-549 (47) 3.6-578 (50) 4.1-581 (50A) 3.5-590 (77) 2.6-510 (77A) 2.6-546 (78) 2.7-520	(2) 2.1-544 (2A) 2.1-518 (2B) 1.4-465 (49) 2.5-505 (51) 2.6-496 (76) 2.1-511 (76A) 2.4-524 (76B) 2.1-513 (76C) 2.2-517 (77A) 2.4-522 (77C) 2.5-540 (77D) 2.5-530 (78A) 2.4-517 (79) 1.9-488 (79C) 1.8-470	(23) 3.0-580 (23A) 3.1-578 (23B) 2.9-578 (23C) 3.9-612 (23D) 4.0-631 (38) 3.9-615 (44) 4.1-612 (69) 3.3-580 (69) 2.8-541	(24) 1.8-464 (24A) 1.6-449 (81) 2.1-481
Averages	3.1X-557	2.2X-511	3.4X-592	1.8X-465
S ₂ - "D" Mill Lean		(5) 2.8-514 (6) 2.1-433 (40) 2.7-507 (51) 2.6-496 (78) 2.7-467 (78A) 3.0-492 (78B) 2.6-471 (78C) 2.6-482	(56) 3.9-503 (61) 4.0-530 (62) 4.2-522 (63) 4.6-549 (65) 5.0-594	(48) 2.1-437 (5) 2.9-429 (64) 2.6-431 (74) 2.6-509 (75) 2.6-518 (75A) 2.7-502 (75B) 2.5-461 (75C) 2.2-485 (82) 1.8-438 (83) 2.1-447 (83) 2.4X-466
Averages		2.6X-483	4.3X-540	2.4X-466
S ₃ -D ₁ and C ₂ Burners - Air Only			(26) 3.9-568	(27) 2.5-444
S ₄ - "C" and "D" Mills Lean			(13) 3.4-476	(14) 2.0-393
S ₅ - "D" Mill on Air Only			(15) 4.2-458	(16) 2.6-350
S ₆ -D ₁ , C ₂ , B ₁ Burners - Air Only			(19) 4.0-500	(20) 2.4-414
S ₉ - "C" Mill on Air Only			(15A) 4.1-496	(16A) 3.4-433

* Secondary air registers reduced to 52% open from the normal level of 70% open.

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Analysis of the data obtained from test runs conducted at 135 to 165 MWe (see Table 3-2 and Figure 3-4) support the following conclusions:

- Baseline operation (all burners firing coal) produced relatively high average NO_x emissions of 592 ppm due to the high excess air level (5.1% O_2). Firing patterns S₁₄- "A" mill off and S₁₇- "F" mill off with their secondary air registers closed gave similar results to S₁ firing so the test data has been combined in calculating the regression line labeled S₁, S₁₄, S₁₇ in Figure 3-4.
- Firing patterns S₉- "C" on air only, S₁₂- "D" mill fired lean, S₁₅- "D" mill fired lean with "A" mill off and S₁₆- "D" mill fired lean with "B" mill off produced similar NO_x emission results so that a single least squares regression has been calculated for these firing patterns. Low excess air firing with these staged firing patterns produced NO_x emission levels below 0.7 lb/10⁶ BTU.
- Firing pattern S₅- "D" mill on air only, produced the lowest NO_x emissions of the nine firing patterns tested at this load level. Test run 16C at 3.2% O_2 in the flue gas produced a 37% reduction in NO_x emission from the baseline level (373 vs. 593 ppm). However, as explained in more detail in Section 3.1.1.2, reheat outlet steam temperatures were reduced below good operating practice during this run and higher excess air as a different firing pattern.

Analysis of the data obtained from the lowest loads tested, 90 to 130 MWe (see Table 3-2 and Figure 3-5), lead to the following conclusions:

- Excess air level as shown by the slopes of the regression lines on Figure 3-5 had a strong influence on NO_x emission levels at low loads. The average reductions in NO_x emissions for each are % reduction in flue gas oxygen were 48, 61 and 58 ppm for firing patterns S₇- "C" and "D" mills on air only, S₁₃- "C" mill on air only with "D" mill lean and the combined results from S₅- "D" mill on air only, S₈- "D" mill on air only with "A" mill off and S₁₁- "D" mill on air only with "A" and "F" mills off, respectively.
- Staged firing pattern S₇, "C" and "D" mills on air only, was the most effective NO_x emission reducing operation tested. Test run No. 29 operated at 2.8% O_2 in the flue gas produced only 230 ppm NO_x emissions or about 59% lower than test run 34 (5% O_2 and 560 ppm NO_x). Several staging patterns operated with "D" mill on air only or "C" mill on air only also reduced NO_x emission levels to about 400 ppm or lower.

In summary, it can be stated that this boiler had a relatively low baseline NO_x emission of 557 ppm. Excess air level had an expected strong influence on NO_x emission levels. Staged firing patterns were found at all load levels (up to 200 MWe) that were capable of reducing NO_x emissions below the 0.7 lb/10⁶ BTU NSPS level.

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TABLE 3-2

TEST PROGRAM DESIGN - COOPER NO. 2 UNIT (90 TO 160 MWe)
(TEST RUN NO., % OXYGEN AND PPM NO. $\times$ (3% O₂, DRY BASIS))

	I ₃ - 135 to 160 MWe		I ₄ - 90 to 130 MWe	
	A ₁ -Normal Excess Air	A ₂ -Low Excess Air	A ₁ -Normal Excess Air	A ₂ -Low Excess Air
S ₁ -All Burners Firing Coal	(90) 4.8-610 (42) 5.4-576			
S ₂ -"D" Mill on Air Only	(66) 4.0-427 (70) 5.0-514	(160) 3.2-373 (71) 4.5-456	(66) 6.7-516	(67) 4.8-413
S ₇ -"C" and "D" Mills on Air Only			(28) 6.7-416	(29) 2.8-230
S ₈ -"D" Mill Air Only, "A" Mill Off				
S ₉ -"C" Mill on Air Only		(160) 3.9-466		
S ₁₀ -"C" and "E" Mills on Air Only	(33) 6.1-467			
S ₁₁ -"D" Mill Air Only, "A" and "F" Mills Off			(36) 7.9-586	
S ₁₂ -"D" Mill Lean, "F" Mill Off	(54) 5.9-550	(55) 4.5-485		
S ₁₃ -"C" Mill Air Only, "D" Mill Lean			(58) 6.8-491	(59) 5.0-382
S ₁₄ -"A" Mill Off	(45) 5.2-631 (46) 5.2-632			
S ₁₅ -"D" Mill Lean, "A" Mill Off	(72) 5.2-582	(73) 4.4-534		(34) 5.0-560
S ₁₆ -"D" Mill Lean, "B" Mill Off	(52) 5.3-572	(53) 2.4-384		
S ₁₇ -"F" Mill Off	(80) 4.4-552			

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Operating Limitations to Combustion Modification

Cooper boiler No. 2 proved to be a very reliable unit with excellent, well-maintained operating controls and sensors. In addition, the large number of mills (6) and burners (18) provided a high degree of firing pattern flexibility. Also, plant management and operating personnel were extremely cooperative and research minded. Thus, over 100 gaseous test runs involving 17 different firing patterns were conducted on this boiler in a relatively short period of time.

However, as on all coal-fired boilers, there are operating limitations that must be carefully examined in designing a short-period test program or in recommending long-period or sustained combustion modifications for NO_x emission control from boilers not designed to meet New Source Performance Standards. Thus, the following factors had to be taken into consideration in testing Cooper No. 2 unit:

- Use of ADS. East Kentucky Power Cooperative, Inc. system demand determined load requirements. Since Cooper No. 2 unit was the most flexible and lowest cost unit in the system, its electrical output was generally controlled by an Automatic Dispatching System (ADS). Consequently, higher than minimum excess air level was generally desirable and firing patterns that gave maximum load flexibility were generally desired over less flexible load firing patterns so that constantly changing load demand was met. For example, test conditions used included firing two mills lean rather than taking a mill out of service, or running a mill lean rather than taking one or more burners out of service.
- Load. Since this boiler is not equipped with overfire air ports, staged firing can be conducted only by firing mills lean or on air only or by taking individual burners out of service. Unless coal quality (Btu content, grindability, moisture content, etc.) is unusually good, staged firing results in reduced loads. Generally, with all mills firing normal quality coal, full load was about 216 MWe. Taking a mill out of service (three burners) reduced load by about 35 to 40 MWe. However, taking one burner off of each of three mills would not reduce load as much as a mill off since more than 2/3 of a mill's capacity can be fed through two active burners of a mill.
- Mill-burner configuration. Figure 3-1 displays the mill burner configuration of Cooper No. 2 unit. A division wall separates the lower furnace into two compartments. If all burners are fired equally, the two compartments will have equal excess air levels (and equal % O₂ in the flue gas). However, if a mill is off, more coal will be fired on one side of the division wall than the other. For example, if staged firing pattern S₅, "D" mill on air only is employed, the left side of the furnace will have seven active burners and the right side eight active burners. This imbalance limits the amount of staging that can be employed by this furnace. Figure 3-6 is a plot of the estimated % stoichiometric air vs. average % O₂ in the flue gas measured in the lower furnace or economizer outlet ducts under S₅- "D" mill on air only operation. From Figure 3-6 it can be seen that operating Cooper No. 2 unit under staged firing pattern S₅, "D" mill on air only, at 13% overall excess air (2.5% O₂) will result in 94% stoichiometric air to the lower burners (bottom four rows), 121%

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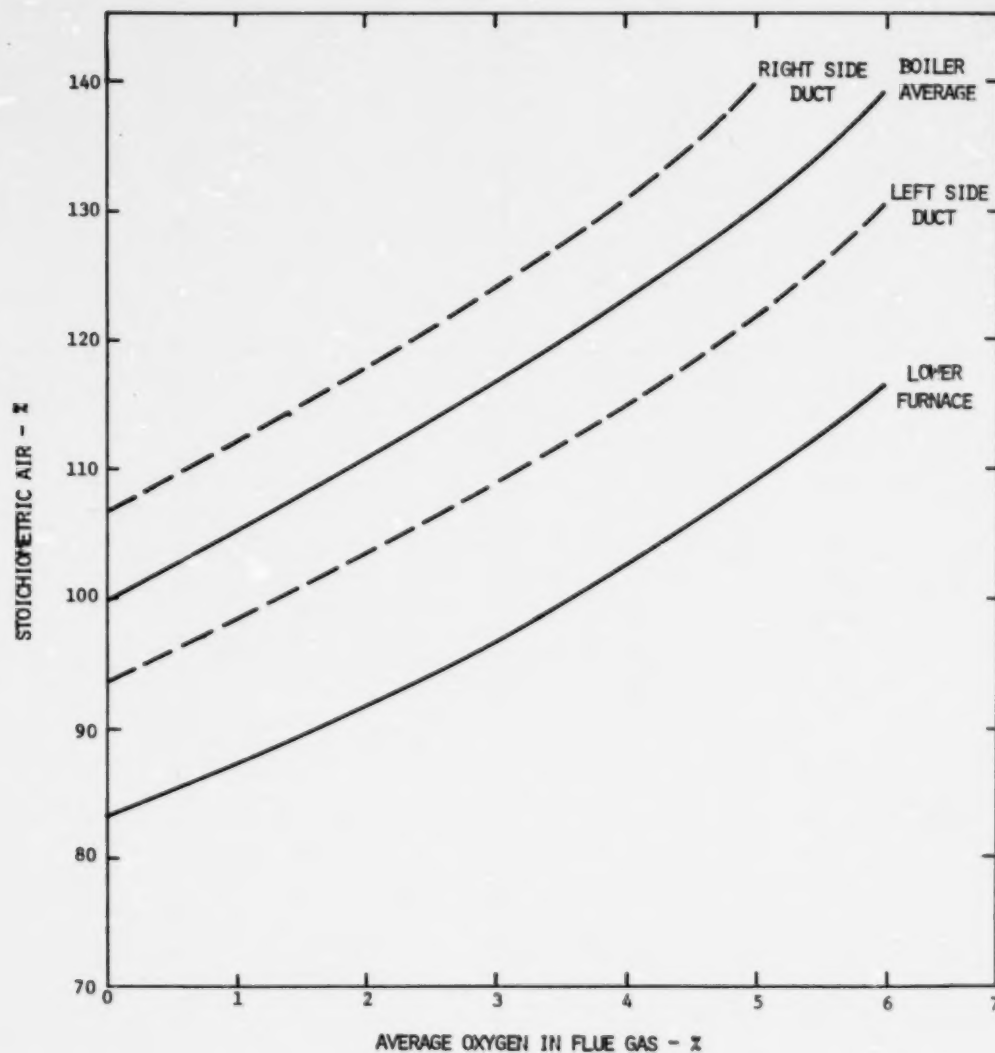


Figure 3-6. % stoichiometric air vs average % O_2 in flue gas measured in lower furnace and economizer outlet ducts under S_5 - "D" mill on air only operation.

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stoichiometric air to the left half of the furnace and only 106% stoichiometric air to the right half of the furnace. Since operation below 6% excess air results in excessive CO emissions, this boiler is limited to an average of 13% excess air rather than 6% excess air under low excess air staged firing pattern S₅.

- Steam temperature control. It is important for efficient and reliable operation that superheat and reheat steam outlet temperatures be maintained near the design level of 814 K (1005°F). Low reheat temperatures tend to occur when less than normal coal is burned on the top row of burners and more than normal air is fed through the top row of burners, and this effect is aggravated with low excess air firing and low load operation. This problem restricted the use of the most effective low excess air, staged firing patterns for NO_x emission reduction to short period tests. Thus, a number of alternative staged firing patterns were tested in order to obtain a reasonable trade off between NO_x emission reduction and maintaining proper steam temperature control for reduced and low load operation.

- Secondary air register settings. The electrical controls for this boiler were established so that burners were ignited at 15% open secondary air registers and normally fired at 70% open. Secondary air registers could be set within the limits of 50% and 100% by board settings in the control room. However, if a burner's secondary air register was set (when operating) to below 50%, automatic controls would stop coal flow to the burner and retract the coal impeller from the furnace. Thus, very low secondary air register settings could not be employed for NO_x emission control.

The above factors limited the effectiveness of combustion modifications to reduce NO_x emissions on this boiler. This necessitated the development of specifications for "best" practical NO_x reduction capabilities for each load range with alternative operating modes if ADS operation, low reheat temperatures or other limitations occurred.

3.1.2 Comanche, Boiler No. 2 (Colorado Public Service Company)

Comanche No. 2 unit is a horizontally opposed fired, balanced draft, Babcock and Wilcox designed boiler equipped with overfire air ports for controlling NO_x emission levels. Each of the four pulverizers feed eight conventional, circular register burners arranged in four rows of four burners each in the front and rear walls of the furnace. There is a single row of four overfire air ports 3.05 m (10 ft) above the top row of burners in both the front and rear walls of the furnace. Secondary air is fed to the burners through three compartmentalized wind boxes arranged so that dampers control the volume of air fed to the lower two rows of burners, upper two rows of burners, and overfire air ports of the front wall as well as the rear wall. The furnace is 13.1 m (43 ft) wide and 13.7 m (45 ft) in depth.

Comanche No. 2 unit has a maximum continuous rating of 11,500 Kg (2,534,000 pounds) of steam per hour and 350 MWe. Steam temperatures and pressures at the superheater and reheater outlets are 814 K (1005°F) at 17.3 MPa (2500 PSIG) and 814 K (1005°F) at 3.93 MPa (555 PSIG) respectively. The furnace volume is 7590 m³ (268,000 cubic feet). Total heating surface is 31,250 square meters (336,350 square feet) of which 26,740 square meters (287,860 square feet) is convection surface.

Boiler performance is based upon the following coal specifications: Proximate analysis - 29.0% moisture, 33.4% volatile matter, 32.4% fixed carbon and 5.2% ash; Ultimate analysis - 5.2% ash, 0.6% sulfur, 3.8% hydrogen, 47.5% carbon, 29 % water, 0.9% nitrogen and 13% oxygen; Heating value 8250 BTU per pound, grindability index 55 and ASTM ash softening temperature of 2150°F (reducing). Predicted furnace efficiency is 84.57% based upon the following heat losses: H₂ and H₂O in fuel 8.68%, dry gas 4.66%, H₂O in air 0.12%, unburned combustible 0.30%, radiation 0.17% and unaccounted for 1.5%.

Table 2 of Appendix B contains a summary of operating and emission data for the 18 test runs conducted on this boiler. Operating variables included in the experimental design were: gross load (full load and minimum load while using all 4 mills), excess air level (normal and high) and overfire air dampers (0 to 100% open). Station operating management requested that no low excess air test runs be conducted because of suspected, potential slagging problems. Secondary air registers were maintained at normal opening (about 65%) and mill fineness was maintained at normal fineness. Table 3-3 presents the test results arranged according to the test program experimental design. Average % oxygen in the flue gas and ppm NO_x (3% oxygen, dry basis) data are given for each test run. Four probes each containing three sampling tubes were placed in the ducts downstream of the economizer and positioned to sample gases from the centers of 12 equal duct areas.

Figure 3-7 is a plot of ppm NO_x vs % open overfire air dampers. Least squares, exponential regression lines have been drawn through the data representing three different operating conditions: upper line - full load at high excess air, middle line - full load at normal excess air and lower line - reduced load at normal excess air. The regression equations are shown within parentheses for each operating condition.

Analysis of the NO_x emission data led to the following conclusions:

- Baseline (0% open overfire air ports and normal excess air) operation at full load produced a NO_x emission level of 726 ppm.
- Full use of the overfire air ports (100% open) reduced NO_x emissions up to 62% (to 278 ppm) from full load baseline operation. Partial use of overfire air ports gave intermediate NO_x reductions: 54% NO_x reduction at 80% OFA, 47% NO_x reduction at 60% OFA, 44% NO_x reduction at 40% OFA, 33% NO_x reduction at 30% OFA and 21% NO_x reduction at 20% OFA.

TABLE 3-3

TEST PROGRAM EXPERIMENTAL DESIGN - COMANCHE NO. 2 UNIT
(RUN NO., AVERAGE % O₂ AND AVERAGE PPM NO_x - 3% O₂, DRY BASIS)

	L1-Full Load (348-354 MWe)		L2-Reduced Load (272-275 MWe)	
	A1-High Excess Air	A2-Normal Excess Air	A1-High Excess Air	A2-Normal Excess Air
S1-OFA 100% Open	(14) 4.8%-356	(6) 4.5%-278 (14A) 4.7%-325		
S2-OFA 80% Open	(7) 5.2%-433	(2) 4.4%-317 (10) 4.8%-348		(13) 5.0%-310
S3-OFA 60% Open		(1) 4.6%-382		
S4-OFA 50% Open	(9) 5.7%-527			
S5-OFA 40% Open		(3) 4.4%-408		(11) 5.4%-400
S6-OFA 30% Open	(15A) 6.9%-613 (15B) 5.4%-613	(16) 4.9%-489		
S7-OFA 20% Open	(8) 5.7%-719	(4) 4.9%-574		
S8-OFA 0% Open		(5) 5.2%-726		(12) 5.6%-607

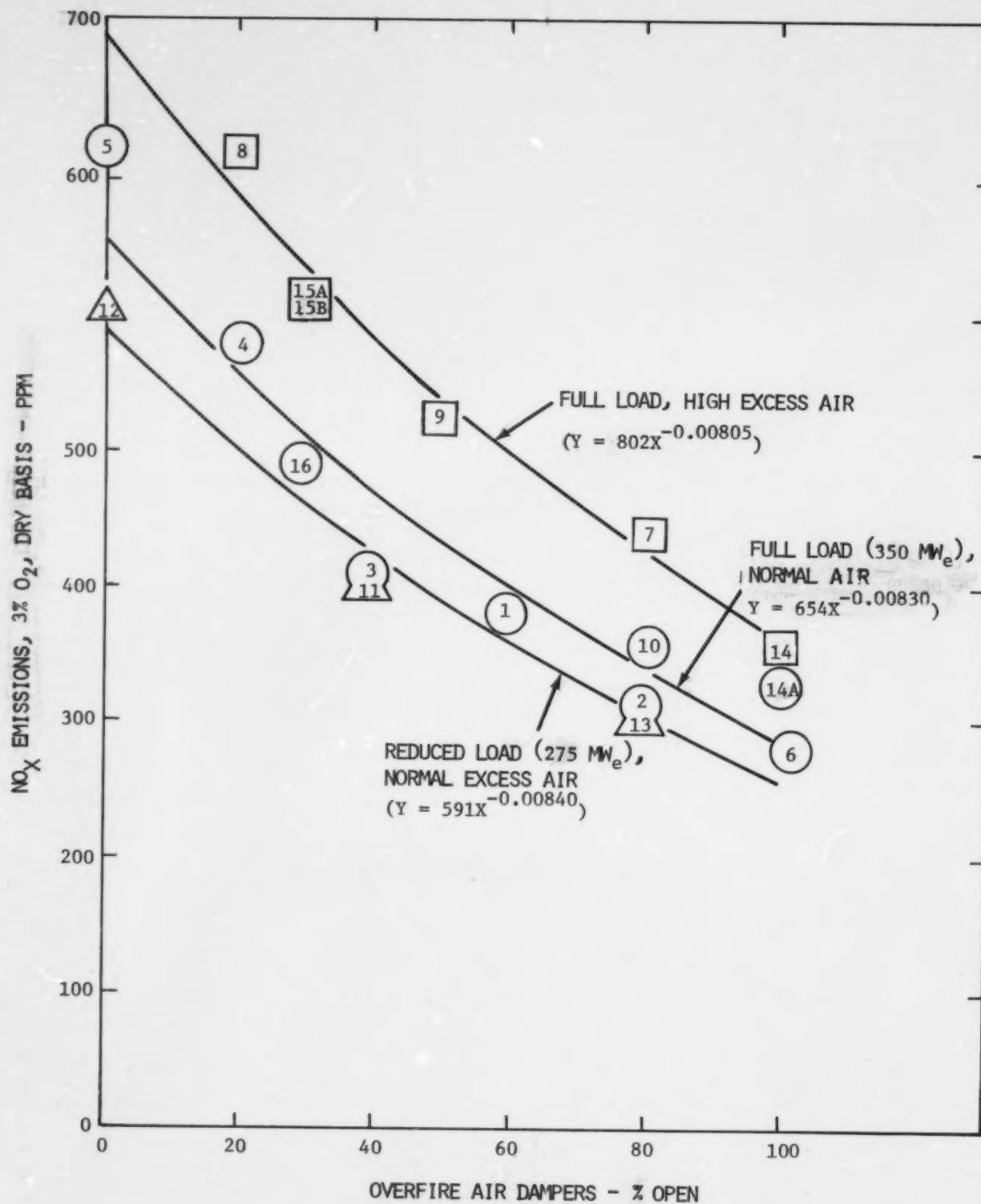


Figure 3-7. NO_x emissions vs overfire air dampers - % open for Comanche No. 2 boiler.

- Increasing excess air from normal (4.5% excess O_2) to high (5.2 to 5.7% excess O_2) increased NO_x emissions by 25 to 34% under full load operation. Thus as expected, excess air level has a large influence on NO_x emission levels.
- Reducing boiler gross load from 355 MW to 275 MW (23%) reduced NO_x emissions by an average of 8%. This result is in line with other pulverized coal fired boilers, i.e., the % reduction in NO_x emission level is lower than the % reduction in load.

In summary, it was found that this new boiler (January, 1976 start of operation) has the capability for excellent NO_x emission reduction through combustion modification at full load operation. Operating with 100% open overfire air dampers at full load and normal excess air resulted in more than a 60% reduction in NO_x emission from baseline operating without overfire air. Excess air level is also an important operating variable for NO_x emission reduction but a small reduction in load (23%) had little effect on NO_x emission levels.

3.1.3 Sewaren Station, Boiler No. 5 (Public Service Electric and Gas Company)

Sewaren boiler No. 5 was selected for testing because it represented a typical, large oil fired boiler with sufficient operating flexibility for NO_x emission control. This Babcock and Wilcox designed boiler is rated at 330 MWe. The pressurized furnace is equipped with 24 burners arranged in three rows of four burners each in both the front and rear walls of the furnace. It is equipped with flue gas recirculation into the furnace at a high or low level for steam temperature control.

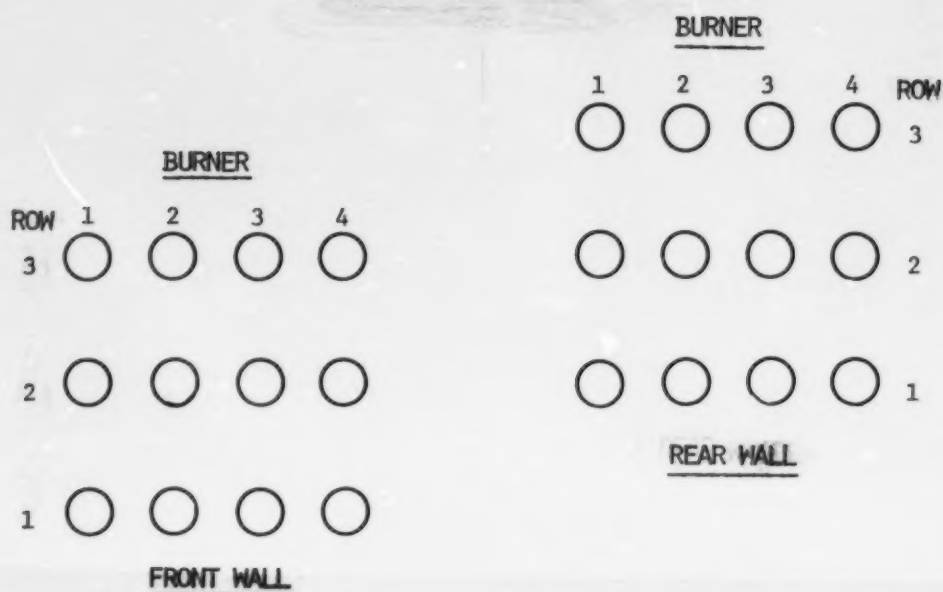
Six stainless steel, gas sampling tubes were used to draw samples from each of the two 3.05 m (10 foot) by 6.10 m (20 foot) ducts leading from the economizer to the air heaters. Two probes, each with short, medium and long tubes were placed into each duct and positioned at the centers of six equal cross sectional areas of each of the two ducts.

Gaseous measurements were made during a 32 minute, steady state period for each of the test runs. Gas stream composites were measured from each of the four probes for two minute periods. This procedure was repeated over four cycles resulting in 16 measurements of each flue gas species during each run.

Table 3-4, Test Program Design - Sewaren No. 5 Unit, presents the test number (circled), average % oxygen and ppm NO_x (3% O_2 , dry basis) for each of the 24 test runs conducted on this unit. Table 3 of Appendix B contains a summary of operating and emission data for each test run. The experimental variables included in the program design were: boiler load, excess air level, firing pattern, flue gas recirculation location and use or non-use of an oil additive.

The high pressure, feedwater heaters on this unit were out of service during these tests, limiting the maximum load to 290 MWe gross output. Low excess air levels were limited to above 2.0% excess O_2 because of the very restrictive plume opacity limitations imposed by local authorities. Five staged firing patterns were tested as shown in Figure 3-8

BURNER CONFIGURATION



STAGED FIRING PATTERNS

	A O O A		A A A O
	O O O O		O O O O
A O O A	O O O O	O A A O	O O O O
O O O O		O O O O	
O O O O		O O O O	

S₂ - STAGED FIRING - I

S₃ - STAGED FIRING - II

	A O O A		A O O A
	A O O A		O A A O
O A A O	O O O O	A O O A	O O O O
O O O O		O A A O	
O O O O		O O O O	

S₄ - STAGED FIRING - III

S₅ - STAGED PATTERN IV

	A A A A
	O O O O
A A A A	O O O O
O O O O	
O O O O	

NOTE: LETTER A'S INDICATE
LOCATIONS OF BURNERS ON AIR ONLY
FOR EACH STAGED FIRING PATTERN

S₆ - STAGED FIRING - V

Figure 3-8. Burner configuration and staged firing patterns (Sewaren No. 5 unit).

where the letter A's indicate locations of burners on air only for each firing pattern. Flue gas was recirculated into the upper or lower level of the furnace. A magnesium oxide fuel additive (to aid boiler cleanliness and stack plume opacity) was used on two test runs for comparison with non-additive fuel.

The experimental test program demonstrated that combustion modification can significantly reduce NO_x emissions on this boiler. Figure 3-9 and Table 3-4 have been constructed to aid in drawing conclusions from the experimental test data. The test results at each load will be discussed first and then the conclusions from the entire study will be summarized.

At the highest load available during the test program (280-290 MWe vs. 330 MWe MCR), baseline NO_x emissions were 311 ppm (182 ng/J). The use of flue gas recirculation to the lower area of the furnace (Test runs 3, 4B and 4C) reduced NO_x levels to 280 ppm (164 ng/J) or by about 10%. Low excess air + flue gas recirculation to the lower area of the furnace (runs 2 and 13) resulted in a further NO_x reduction to 248 ppm (145 ng/J) or 20% less than baseline NO_x emission levels.

Test runs No. 20 and 21 were conducted with the fuel oil containing a chemical additive. The NO_x emission levels of these runs can be compared with test runs 1B, 2, 3, 4B and 4C which were operated with no fuel additive. Analysis of the NO_x emission data showed no significant difference after properly correcting for excess air level. The next to top regression line on Figure 3-9 calculated from these seven test runs (shown in light circles) shows the similarity of NO_x emission results from operation with and without magnesium oxide additive.

Three staged firing patterns: S_2 , S_3 and S_4 (see Figures 3-8, 3-9 and Table 3-4) were tested at the highest load available. Under staged firing pattern S_2 (top wing burners on air only), two test runs were conducted with flue gas recycled above the burners and three test runs with flue gas recycled below the burners. Operation with flue gas injected below the burners reduced NO_x emissions by 7% compared to flue gas injected above the burners. This result is very similar to the 10% reduction obtained under normal firing (S_1) operation.

Since flue gas recycled to the lower furnace was effective for both S_1 and S_2 operation, this procedure was followed for the other staged firing patterns tested. Low excess air operation with staged firing patterns S_2 , S_3 and S_4 gave very similar NO_x emission levels of 211 to 216 ppm, about 32% below baseline NO_x emissions of 311 ppm (182 ng/J).

Reduced load operation (210 MWe vs. 290 MWe) with normal firing resulted in lowered NO_x emissions. Low excess air, normal firing operation produced 211 ppm (123 ng/J) NO_x emissions, about 32% below the baseline emission rate. Increasing excess air to 6% excess O_2 increased NO_x emissions from 211 to 286 ppm or by about 36%.

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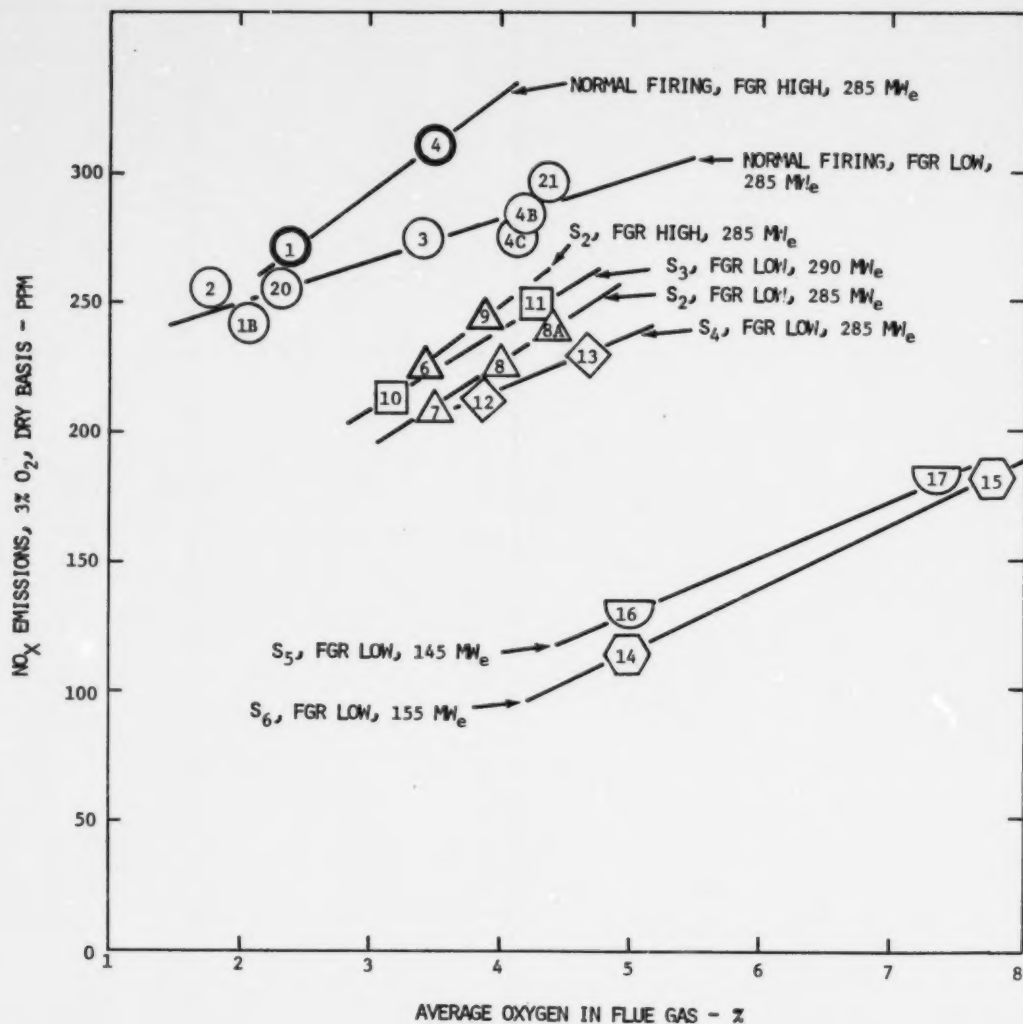


Figure 3-9. NO_x emissions vs flue gas oxygen measurements on Seward No. 5 unit firing oil.

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TYPING GUIDE SHEET

TABLE 3-4

TEST PROGRAM DESIGN - SEWAREN NO. 5 UNIT
(TEST RUN NO., % OXYGEN AND PPM NO. $\times$ (3% O₂, DRY BASIS))

		L ₁ -280-290 MWe		L ₂ -210 MWe		L ₃ -138-146 MWe	
		A ₁ -Normal Exc. Air	A ₂ -Low Exc. Air	A ₁ -Normal Exc. Air	A ₂ -Low Exc. Air	A ₁ -Normal Exc. Air	A ₂ -Low Exc. Air
S1-Normal Firing	F1-FGR High	(4) 3.5-311	(1) 2.4-270	(19) 6.0-286	(18) 2.5-211		
	F2-FGR Low	(3) 3.4-277 (4B) 4.1-285 (4C) 4.2-277 (21) 4.4-295	(2) 1.8-254 (1B) 2.1-243 (20) 2.3-256				
S2-Staged Firing-I	F1-FGR High	(9) 3.8-244	(6) 3.4-226				
	F2-FGR Low	(8) 4.0-226 (8A) 4.4-241	(7) 3.5-211				
S3-Staged Firing-II	F2-FGR Low	(11) 4.3-249	(10) 3.2-216				
S4-Staged Firing-III	F2-FGR Low	(13) 4.7-232	(12) 3.9-216				
S5-Staged Firing-IV	F2-FGR Low					(15) 7.8-183	(14) 5.0-114
S6-Staged Firing-V	F2-FGR Low					(17) 7.5-183	(16) 5.0-131

Four test runs were conducted with one-third of the 24 burners on air only, while operating at about one-half load of 138 to 146 MWe. Two firing patterns S_5 and S_6 (see Figure 3-8) were tested, each at normal and high excess air. Excess air level had a large influence on NO_x emissions with a 28 to 38% increase in changing from low excess air to normal excess air. Staged firing pattern S_5 produced slightly less NO_x emissions than staged firing pattern S_6 . This result can probably be explained by the increased active burner spacing employed in S_5 compared to S_6 .

The conclusions from the Sewaren boiler No. 5 test program can be summarized as follows:

- With the exception of fuel oil additive, all combustion modification variables (load, excess air level, firing pattern and FGR location) tested had a significant influence on NO_x emission levels.
- Reducing load by 28% reduced NO_x emissions by 22% under normal firing operation.
- Flue gas recycle to the lower furnace level resulted in a small (7 to 10%) but statistically significant reduction in NO_x emission levels.
- Reduced excess air levels, as expected, had a marked effect on NO_x emission levels at all load-firing pattern operations.
- Staged firing (burners on air only) operation resulted in reduced NO_x emission levels. The combination of low excess air, staged firing and flue gas recycle to the lower furnace reduced NO_x emission by up to 32% at the highest loads tested.

3.1.4 T. H. Wharton, Gas Turbine No. 43
(Houston Lighting and Power Co.)

T. H. Wharton Gas Turbine No. 43 was the first gas turbine to be tested in Phase II of this program. (Morgantown Gas Turbine No. 3 was tested while firing oil in Phase I of the program.) This General Electric model MS7001B gas turbine is of modern design, has a maximum continuous rating of 50 MWe and a short term peak output rating of 56 MWe. It fires natural gas and is equipped with water injection capabilities for NO_x emission control. Flue gas samples were taken from the centers of four equal duct cross-sectional areas from four stainless steel sampling probes.

Table 4, Appendix B contains a summary of the major operating and emission data obtained from the 16 test runs conducted on this unit. Table 3-5 presents the test data (run number, % O_2 , ppm NO_x , ppm CO and ppm HC) arranged according to the test program experimental design. Figures 3-10 through 3-12 have been constructed to aid in the analysis and presentation of the data.

As expected both gross load and water injection rate have a significant effect on NO_x , CO and HC emission rates. At full to peak load, baseline NO_x emissions were 111 ng/J (73 ppm - 15% O_2 , dry basis). As the top line on Figure No. 3-10 illustrates, NO_x emissions decreased linearly with decreasing load. Reducing load from 56 MWe to 20 MWe (64%) reduced NO_x emissions by 45% (74 ppm to 41 ppm).

Water injection had a larger influence on NO_x emissions than load reduction. At peak load (57.5 MWe) 1.9% water injection (% of combustion air) reduced NO_x emissions to 17 ng/J (11 ppm on a 15% O_2 , dry basis) or an 84% reduction from baseline NO_x emissions. Figure 3-11 presents a least square exponential curve, ppm (15% O_2 , dry basis) = $70.3 e^{-1.007\% \text{H}_2\text{O}}$, which has been fitted to the nine test runs conducted at full load (52-58 MWe). Water injection was also effective in reducing NO_x emissions at lower loads of 30 and 43 MWe.

CO and gaseous HC emissions increased as the level of water injection was increased. At full load CO emissions increased non-linearly from about 2 to 60 ppm (15% O_2 , dry) as water injection was increased from 0 to 1.9% of combustion air. Figure 3-12 presents a plot of the CO emissions vs. % water injection data. An exponential curve, ppm CO = $2.3e^{1.70\% \text{H}_2\text{O}}$ has been fitted to the maximum load test data. At less than full load, CO emissions increased rapidly with increased water injection resulting in a lower trade-off between NO_x reduction and increased CO emission. Gaseous HC emissions, at full load operation showed little or no increase until the maximum level of 1.9% water injection. However, at a reduced load of 30 MWe, 0.75% water injection increased gaseous HC emissions to 131 ppm (15% O_2 , dry basis) from 5 ppm under zero water injection.

TABLE 3-5

TEST PROGRAM EXPERIMENTAL DESIGN - WHARTON NO. 43 GAS TURBINE
(TEST NO., % O₂, PPM NO_x, PPM CO, PPM HC)

	L1- (52-58 MWe)	L2- (43 MWe)	L3- (30 MWe)	L4- (20 MWe)
W1-No Water Injection	① 15.5, 71, 2, 2 ④ 15.5, 73, 4, 2 ②③ 15.7, 74, 2, 1	② 16.3, 60, 3, 1 ⑨ 16.0, 62, 4, 4	②⑧ 17.5, 64, 18, 5	③ 18.1, 40, 41, 3 ②⑦ 18.1, 42, 42, 10
W2-0.5% Water	⑦ 15.0, 40, 5, 3	⑧ 16.0, 34, 7, 4		
W3-0.75% Water	⑤ 15.1, 32, 6, 5 ②⑥ 15.2, 32, 6, 2		②⑨ 17.6, 10, 336, 131	
W4-1.0% Water	⑥ 15.0, 25, 4, 4			
W5-1.35% Water	②⑤ 15.2, 18, 30, 3			
W6-1.9% Water	②④ 15.1, 11, 60, 51			

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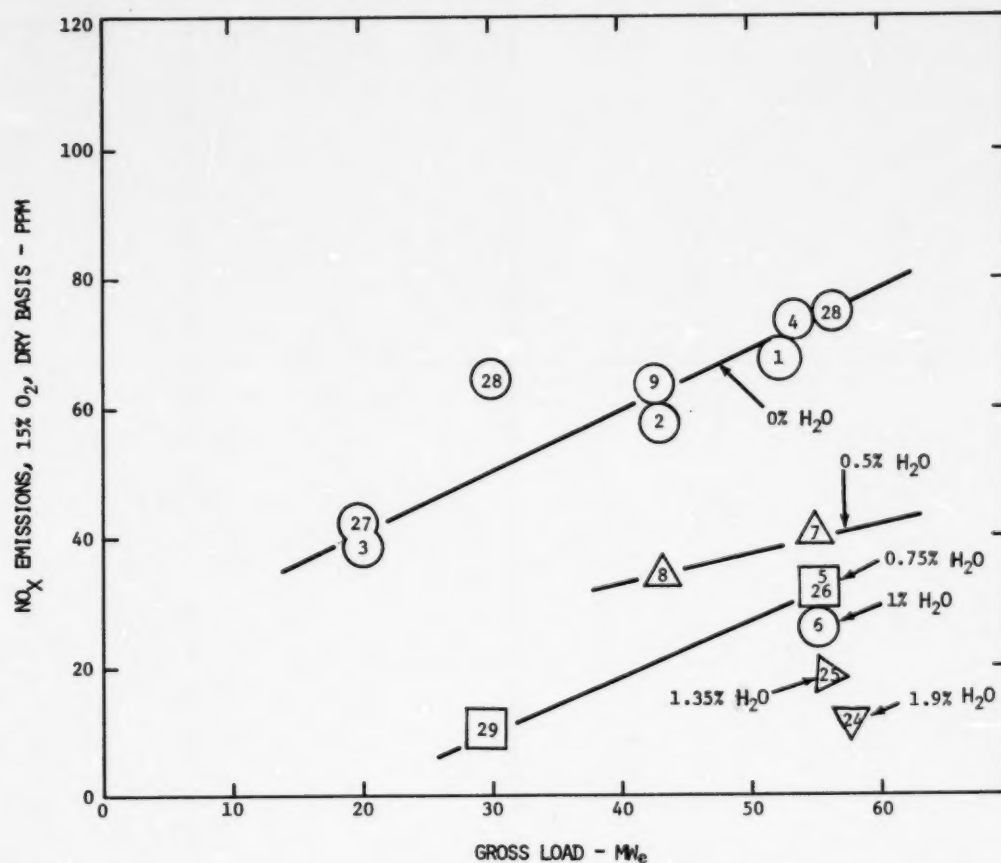


Figure 3-10. PPM NO_x vs gross load - Wharton No. 43 unit firing gas.

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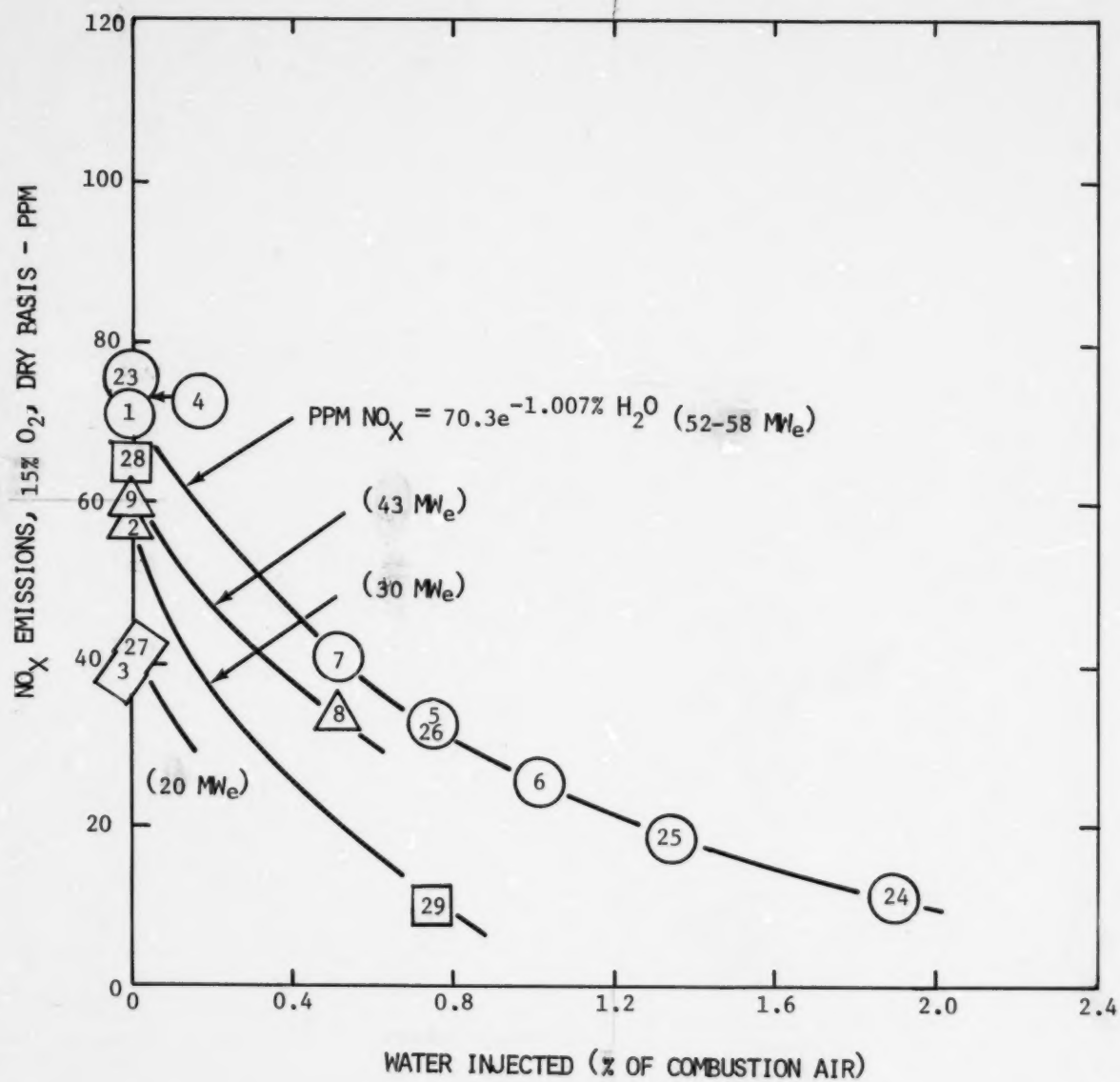


Figure 3-11. NO_x emissions vs % water injected - Wharton No. 43 gas turbine firing gas.

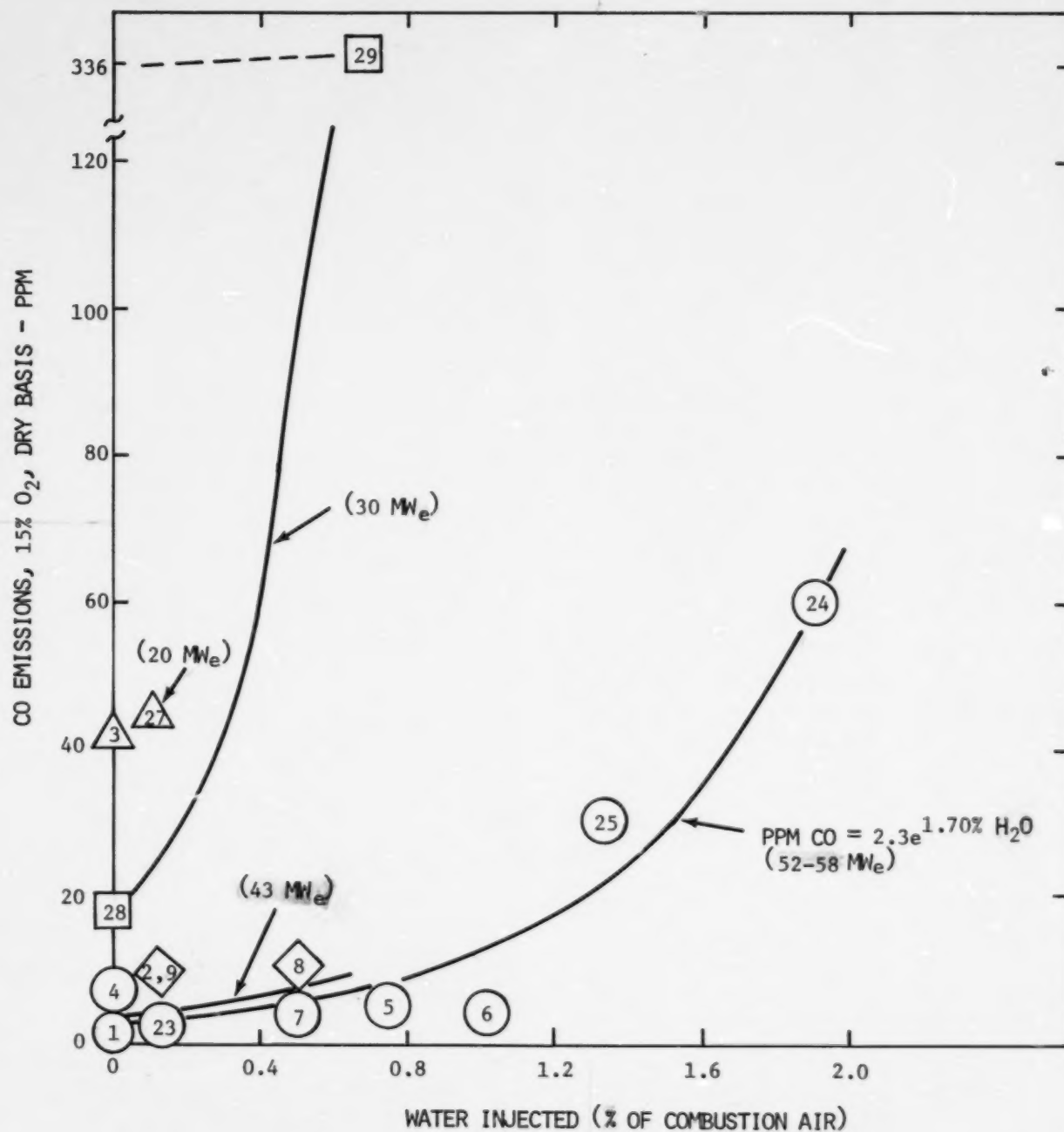


Figure 3-12. CO emissions vs % water injected - Wharton No. 43 unit firing gas.

3.1.5 T. H. Wharton, Gas Turbine No. 42
(Houston Lighting and Power Co.)

T. H. Wharton unit No. 42 was the third gas turbine to be tested in this field test program. This General Electric model MS7001B gas turbine is also of modern design, has a rated output of 50 MWe with a peak load of 54 MWe. It is equipped to burn gas or oil and has water injection capabilities with either fuel. All of the test runs conducted on this unit were made while firing No. 2 distillate fuel oil. Plans to test with gas had to be aborted, first because of turbine and other equipment problems and later because of a Houston Lighting and Power Company labor strike.

Flue gas samples were taken from the centers of 12 equal areas in the duct work leading to the stack. Gas samples were taken from each of the 12 sample points and analyzed separately in the first test run on this unit (Run No. 10). As previously found in tests conducted by General Electric, there was an insignificant degree of gaseous stratification within the duct. For example, % O₂ varied from 16.4 to 16.5 and NO_x emissions varied from 77 to 83 ppm on an as-measured basis. Consequently, on the remaining test runs the gaseous samples from short, medium and large tubes were composited into each of the 4 probes before measurement.

Table 5 of Appendix B contains a summary of operating and emission data for the 13 test runs conduction on this unit. Table 3-6 presents test data (run number; % O₂; ppm NO_x, ppm CO and ppm HC on a 15% O₂ dry basis) according to the test program experimental design. Operating variables were gross load (idle or 0 to 55.5 MWe) and level of water injection (0 to 2.3% of combustion air, or about 0 to 1.2 kg H₂O/kg fuel).

Figures 3-13 through 3-16 have been plotted to display the relationship between flue gas emissions and operating variables. Figure 3-13 is a plot of ppm NO_x (15% O₂, dry basis) vs. gross load output. Linear, least squares regressive lines have been fitted through the data from 0 and 0.75% water injection operation. Baseline NO_x emissions were 214 ng/J (127 ppm), very similar to the 224 ng/J (133 ppm) previously measured on Morgantown's No. 3 oil fired gas turbine. Thus, firing oil produces about 60% higher NO_x emissions than gas firing under full load uncontrolled operation. Operating at reduced loads, reduced NO_x emissions linearly; for example to 65 ng/J (38 ppm) or by 70% at idle (0 MWe) compared to baseline emissions.

Water injection was extremely effective in reducing NO_x emission levels on this oil fired gas turbine. A 90% NO_x emission reduction was obtained at full load when operating with 2.3% water injection. Lower water injection rates were less effective, but still reduced NO_x emission rates by substantial amounts. Figure 3-14 is a plot of NO_x emissions vs. % water injection. Least squares, exponential regression curves have been fitted to the data for the full, intermediate and low load output test data.

TABLE 3-6

TEST PROGRAM EXPERIMENTAL DESIGN - WHARTON NO. 42 GAS TURBINE
(TEST NO., % O₂, PPM NO_x, PPM CO, PPM HC)

	L ₁ - (51-56 MWe)	L ₂ - (37-40 MWe)	L ₃ - (20 MWe)	L ₄ -Idling (0 MWe)
W1-0% Water	(14) 15.3, 127, 4, 3	(10) 16.5, 106, 3, 3	(19) 17.3, 72, 19, 3	(22) 19.1, 38, 145, 25
W2-0.5% Water			(20) 17.3, 25, 60, 7	
W3-0.75% Water	(15) 15.1, 57, 8, 1	(11) 16.5, 36, 3, 3	(21) 17.4, 19, 114, 19	
W4-1.21% Water		(13) 16.4, 21, 64, 7		
W5-1.50% Water	(16) 14.9, 29, 9, 1	(12) 16.4, 17, 142, 20		
W6-2.00% Water	(17) 14.7, 20, 34, 2			
W7-2.30% Water	(18) 14.6, 13, 53, 2			

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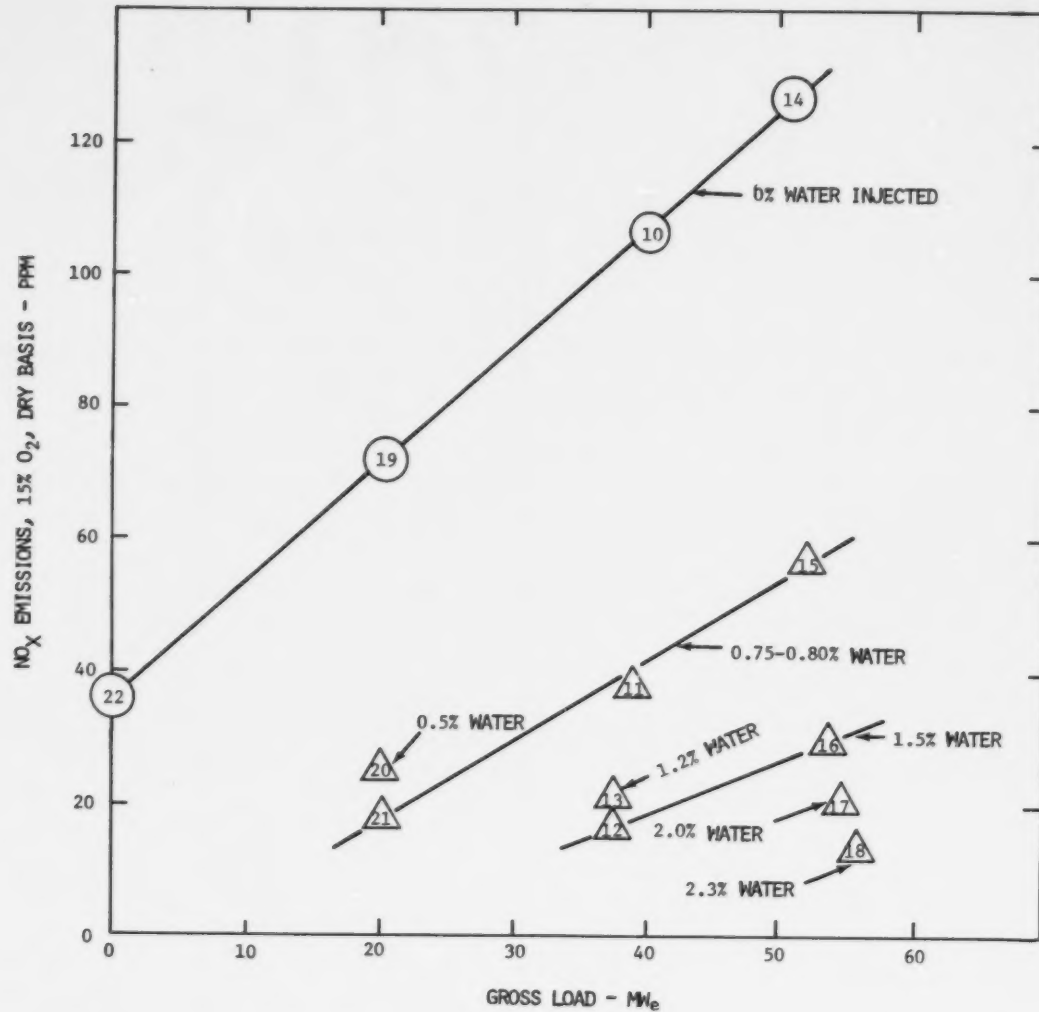


Figure 3-13. PPM NO_x emissions vs gross load on Wharton No. 42, firing oil.

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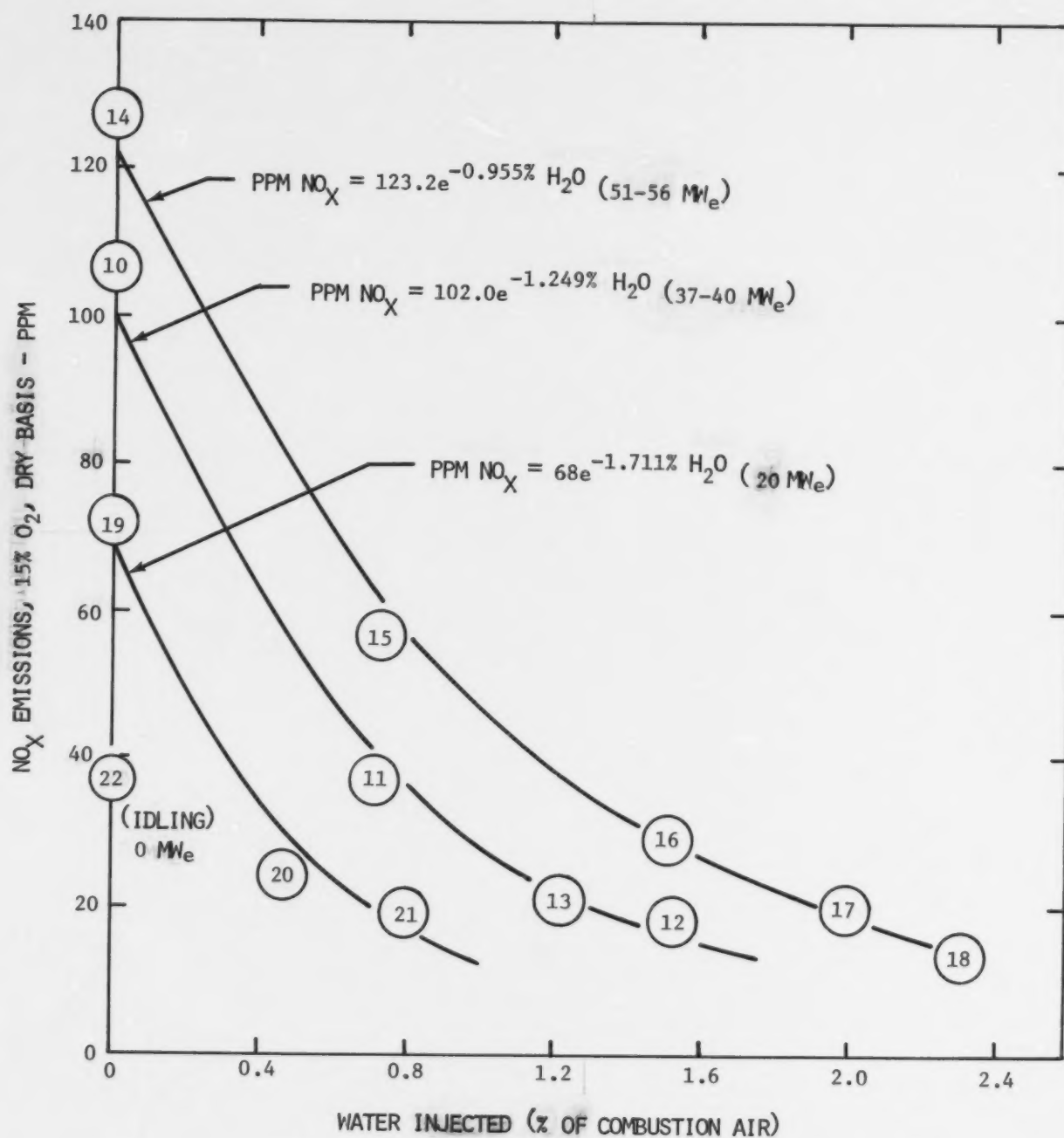


Figure 3-14. NO_x emissions vs % water injected - Wharton No. 42 gas turbine firing oil.

CO emissions increased as the rate of water injection was increased. Figure 3-15 is a plot of ppm CO (15% O₂, dry basis) vs. % water injection. Least squares, exponential regression curves have been calculated and plotted for each load tested. As these curves show, CO emissions start to increase rapidly at water injection rates greater than 1.6% water injection full load, 0.8% water at 40 MWe and 0.4% water injection at 20 MWe. At zero load output (idling) (test run No. 22), the highest CO emissions were measured even though no water was injected.

Gaseous hydrocarbon emissions, as expected, behaved very similar to CO emissions, although the HC emissions were considerably lower in absolute numbers. Figure 3-16 is a plot of ppm HC (15% O₂, dry basis) vs. % water injection. At full load, HC emissions did not increase significantly with increased water injection. However, at 40 MWe, CO emissions increased with water injection rates above 0.8%, and at 20 MWe output HC emissions increased with water injection at 0.5% and above. As with CO measurements the maximum HC measurements occurred when the gas turbine was idling with zero MWe output.

In summary, the test programs on three gas turbines have demonstrated that NO_x emissions were higher when firing oil rather than gas, and that water injection was extremely effective in reducing NO_x emission levels. However, both CO and gaseous HC emissions generally increased as the level of water injection was increased beyond a threshold value. This does not create a problem at full load but limits the amount of water injection at medium to low loads. (Efficiency effects were not measured.)

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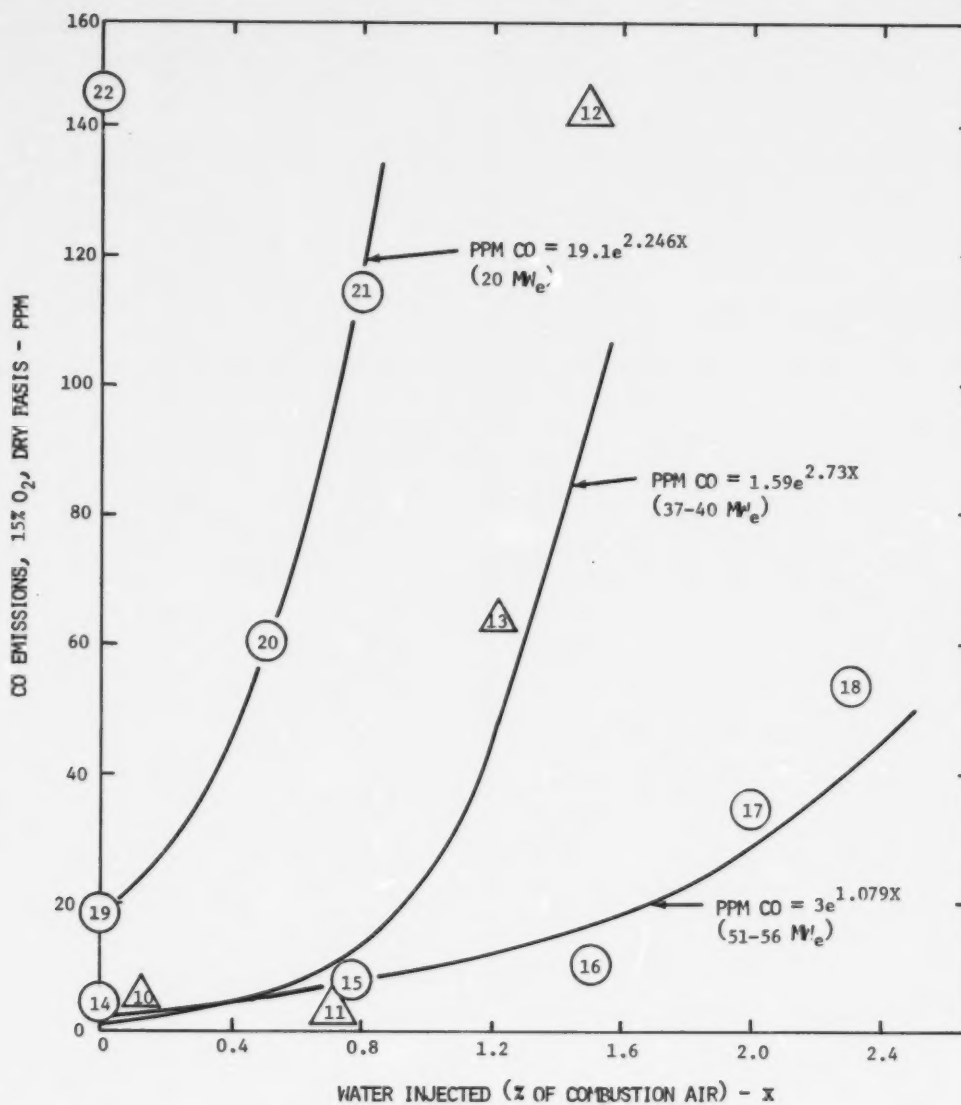


Figure 3-15. CO emissions vs % water injected - Wharton No. 42 gas turbine firing oil.

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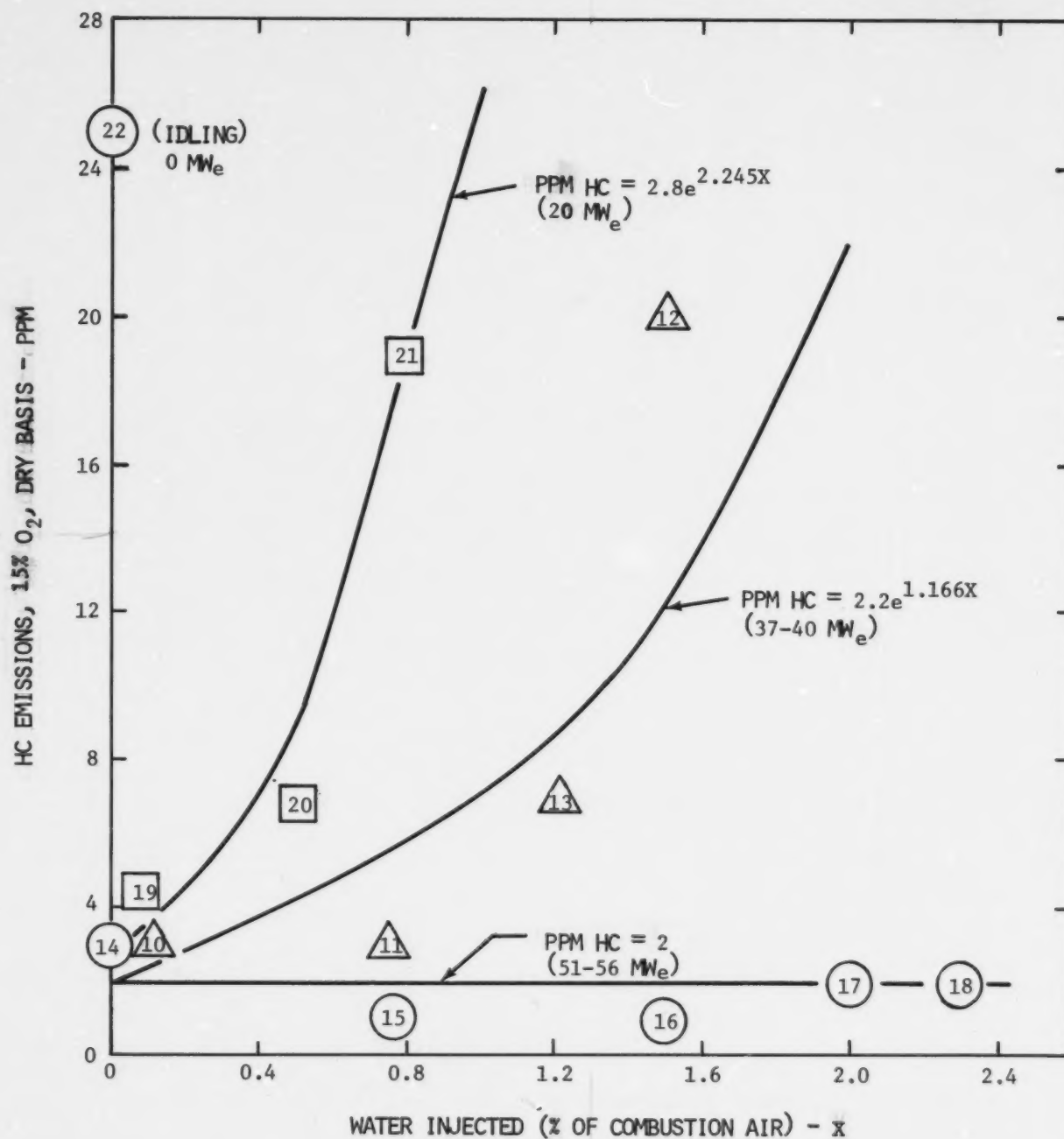


Figure 3-16. HC emissions vs % water injected - Wharton No. 42 gas turbine firing oil.

3.1.6 Crist Station, Boiler No. 7
(Gulf Power Company)

Crist Station Boiler No. 7 is a horizontally opposed fired, dry bottom, single furnace Foster Wheeler boiler rated at 500 MW capacity. This unit was selected for testing because it is a large, pulverized coal burning unit of modern design. It also appeared to have the necessary operating flexibility and management support so that it was a good candidate for the long-term corrosion test program. The boiler has a 291,100 cubic foot furnace volume with a furnace wall area of 26,044 square feet. The furnace measures 52 feet 5 inches wide and 40 feet in depth. Maximum continuous rated steam flow is 3,626,000 PPH. Superheat steam outlet pressure is 2486 psig. Superheat and reheat temperatures are 811/811 K (1000/1000°F) respectively. Six pulverizers feed 24 burners arranged in three rows of four burners each in the front and rear walls of the furnace. Design heat liberation is 16,250 Btu/hr/ft³ when firing 394,000 pounds of coal per hour. Design performance was based on coal with the following specifications: proximate analysis of 8.5% moisture, 38% volatile matter, 45% fixed carbon and 8.5% ash; ultimate analysis of 3.7% sulfur, 4.7% hydrogen, 66.6% carbon, 8.5% water, 1.2% nitrogen and an "as fired" heat content of 12,000 Btu per pound.

Operating and emission data for 29 test runs are summarized in Appendix B, Table 6. Operating variables listed are gross load, excess air level, secondary air register settings, and firing pattern. Emission measurements include visual opacity of the stack plume, average % oxygen and ppm NO_x (3% O₂, dry basis).

Table 3-7 presents % O₂ and ppm NO_x data for each test run arranged according to the test program experimental design. The operating variable, secondary air register setting, is not shown in Table 3-7 since the limited data obtained on this variable showed only a small, statistically nonsignificant influence of NO_x emission levels. Limited data were obtained because some of the secondary air register settings were inoperable and connecting pins were sheared when attempting to adjust others.

The operating variables found to have a statistically significant influence on NO_x emission levels were load, excess air level, and firing patterns. Figure 3-17, "ppm NO_x vs. % Oxygen in Flue Gas," has been constructed to indicate the most important relationships found in analyzing the test data. The numbers within the symbols indicate the run number while the symbols indicate the various firing patterns tested. The lines drawn on Figure 3-17 are least squares, linear regression lines for ppm NO_x vs. % oxygen calculated for each firing pattern.

The strong influence of excess air level on NO_x emission levels for all firing patterns is indicated by the steep slopes of the lines drawn on Figure 3-17. Very close agreement was found in the calculated regression coefficients (change in ppm NO_x for a 1% change in oxygen) for the various firing patterns, i.e., 69, 80, 81, 59, and 76 for firing patterns S₁, S₂, S₃, S₆, and S₇, respectively. Since excess air levels could be reduced by at least 2% to as much as 5% from normal to low excess air operation

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TABLE 3-7

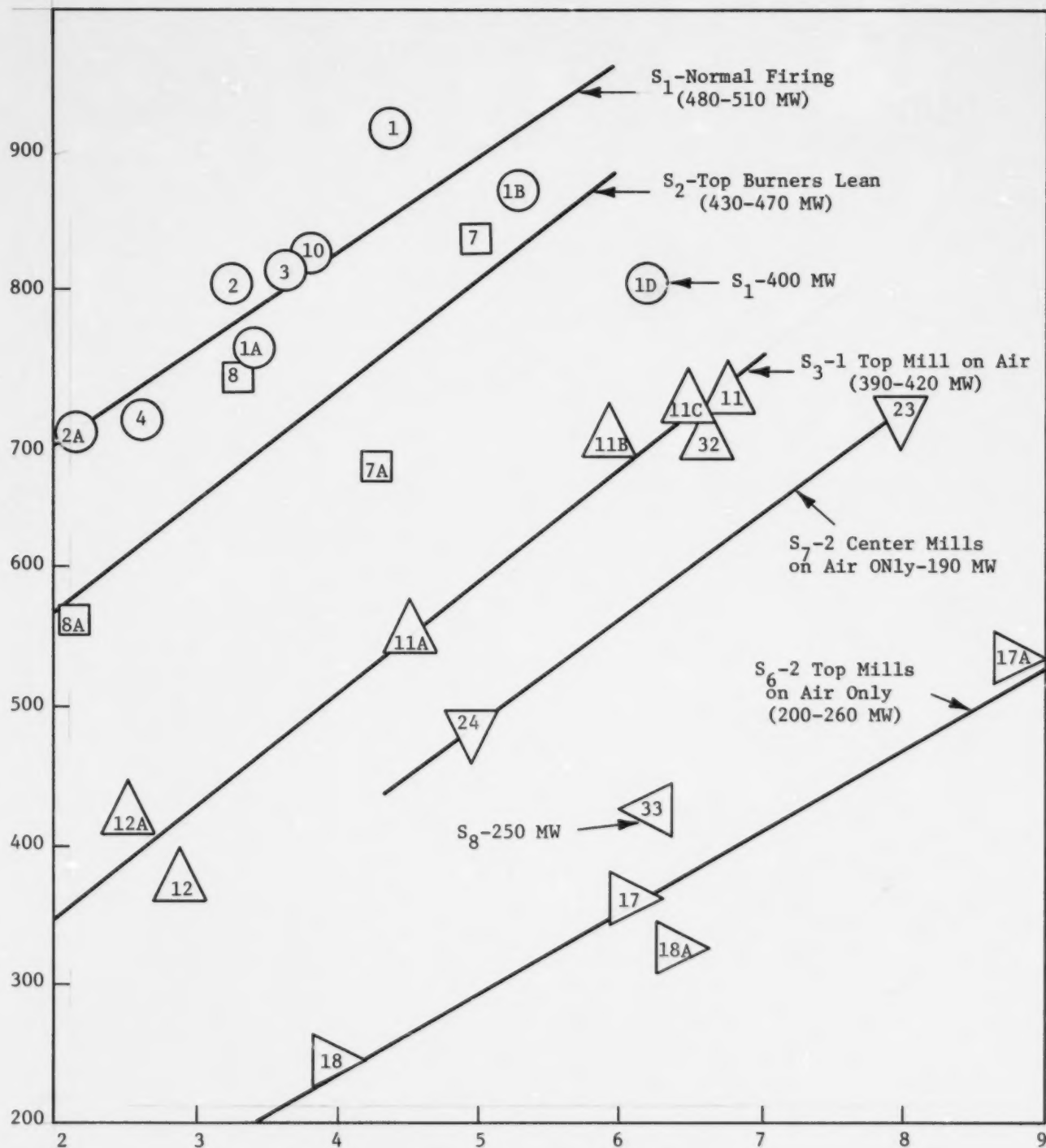
TEST PROGRAM EXPERIMENTAL DESIGN - CRIST STATION, ROTER NO. 7
(RUN NO., AVERAGE % O₂ AND AVERAGE PPM NO_x - 3% O₂, DRY BASIS)

	L1-Full Load (480-510 MW)			L2-Reduced Load (380-440 MW)			L3-Low Load (175-260 MW)		
	A1-Normal Excess Air	A2-Low Excess Air		A1-Normal Excess Air	A2-Low Excess Air		A1-Normal Excess Air	A2-Low Excess Air	
S ₁ -Normal Firing, All Burners Firing Coal	① 4.3% 913 ② 3.4% 750 ③ 3.6% 810 ④ 5.2% 864 ⑤ 3.7% 813	② 3.2% 797 ③ 2.1% 696 ④ 2.6% 702	⑩ 6.1% 809	⑦ 4.2% 666 ⑧ 2.1% 556	⑪ 6.6% 720 ⑫ 4.4% 548 ⑬ 5.8% 688 ⑭ 6.5% 714 ⑮ 6.6% 693	⑬ 2.8% 371 ⑭ 2.4% 415	⑬ 6.0% 363 ⑭ 8.8% 532	⑮ 4.0% 244 ⑯ 6.3% 327	
S ₂ -Top Row Burners Fired Lean, 2 Other Burners Fired Rich	⑦ 5.0% 835	⑧ 3.3% 746					⑮ 7.9% 712 ⑯ 6.2% 421	⑰ 4.9% 483	
S ₃ -One Top Mill on Air Only (C or F Mill)									
S ₄ -Top Wing Burners-Air Only	⑬ ⑭	⑮ ⑯					⑰ ⑱		
S ₅ -Middle Mills-Air Only (A and D Mills)									
S ₆ -Top Mills-Air Only									
S ₇ -Bottom Mills-Air Only (B and E Mills)									
S ₈ -D and F Mills-Air Only									
S ₉ -B, C and F Mills-Air Only							⑳ 9.7% 179		

*Except for Test Run 7 at 466 MW and Test Run 8 at 472 MW.

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Average % Oxygen Measured in Flue Gas

Figure 3-17. PPM NO_x vs. % Oxygen in Flue Gas
(Crist No. 7 Unit)

without violating the 200 ppm CO maximum emission level guideline or increasing stack plume opacity, this represented an important operating variable for NO_x emission control. Thus, NO_x emissions were reduced by 16% in changing from a full load (480-510 MW) baseline operation (4% O₂) of 827 ppm, to 696 ppm under low excess air (2.1% O₂) operation.

Reducing load by 62% from the 480 to 510 MW range to 190 MW under normal excess air firing operation resulted in lowering NO_x emissions by about 37%. Staged firing generally resulted in reduced loads as well as reduced NO_x emission levels. Separating the effect of staged firing on NO_x emission levels from the load effect indicate the following. Staged firing operation, S₂, top burners fired lean (by reduced coal flow to top row of burners) and normal excess air (4% O₂) resulted in a 12% reduction in NO_x emissions (827 ppm to 728 ppm) with about 5% due to load reduction (496 to 451 MW average) and the remaining 7% due to staged firing. Staged firing operation, S₃, (1 top mill on air only) resulted in a 39% reduction in NO_x emissions (to 509 ppm from 827 ppm) with about 12% due to load reduction and 27% due to staged firing. Finally, S₆, staged firing with both top mills on air only produced a 72% NO_x emission reduction with about 32% due to reduced load (230 MW vs. 495 MW). It should be noted that part of the load reduction experienced during the test period was due to abnormal operating difficulties such as partial air heater plugging.

The combined effect of low excess air and staged firing operation resulted in further NO_x emission reductions as would be expected. Thus, the ppm NO_x levels (and % NO_x reduction from the 827 ppm measured under baseline operation) were 451 (-31%), 400 (-52%) and 244 (-70%) for S₂, S₃ and S₆ staged firing patterns, respectively. These results indicate that this boiler has a substantial potential for NO_x reduction through modified combustion operation.

3.2 Particulate Emission Results

Particulate emissions in pulverized coal fired utility boilers are affected by the ash content of the coal fired, coal fineness, burner design, type of firing and by burnout problems (increased carbon on particulates). Since no changes were made in pulverizer mill fineness adjustment during the particulate tests conducted in the course of this contract, coal fineness is not a valid contributing factor. Combustion modification techniques used to control NO_x emissions, however, result in less intense combustion conditions than those corresponding to conventional firing methods and these techniques such as, lowering and optimizing excess air levels, staging the combustion process and re-adjustment of burner dampers to decrease the air supplied to the flame zone can affect carbon burnout, which may adversely affect particulate emissions. Lowering excess air tends to limit the amount of oxygen available for completion of the combustion process. This factor directionally increases the probability of burnout problems. Staging the combustion pattern, where the majority of the burners are operated at substoichiometric air supply conditions and the remaining air is introduced either through inactive burners or overfire air ports to complete the combustion process, may have similar effects. Since staged combustion limits the amount of available oxygen in the burner zone, flames are lengthened, and turbulence is reduced, resulting in slower diffusive mixing of air and fuel. Thus, staged firing may also tend to increase unburned combustibles.

Beyond this issue of combustibles with potential changes in particulate mass loading, a further question to answer is whether particulate size distribution may be affected by low NO_x operation of coal fired boilers. Part of the overall program plan, therefore, was to obtain information on the effect of combustion modifications on particulate mass loading and flyash particle size distribution. These measurements were made upstream of the electrostatic precipitators in order to show the direct effect of the NO_x reduction techniques. Measurements of total mass loading and particle size distribution were made under baseline and optimized low NO_x operating conditions to determine the extent of adverse effects of staged firing and other NO_x combustion modifications. Flyash was analyzed for unburned carbon content for use in these comparisons. Such information is needed to evaluate the impact of potential changes in particulates on electrostatic precipitator performance and to determine the effect of combustion modifications on trace species emission.

The particulate emission tests were conducted using sampling trains complying with EPA Method 5 requirements. The Method 5 type trains were modified to incorporate Brink, multistage cascade impactors for particle size determination in the heated oven between the cyclone and filter of the normal EPA train. This arrangement permitted obtaining mass loading and particle size distribution data simultaneously under isokinetic conditions with the Brink impactor located outside of the boiler. All tests were made in the boiler flue gas ducts downstream

of the airheaters but upstream of any collecting devices, such as mechanical dust collectors or electrostatic precipitators. Consequently, the dust loadings are higher than at the outlet of the precipitator, but the results are not affected by the existing collection devices. Comparison of the test results taken under baseline operating conditions with data obtained under "low NO_x" operation, therefore, provides a direct determination of potential side effects of NO_x reduction techniques on particulates.

In earlier ER&E field studies (2), some "side effects" attributed to "low NO_x" firing were observed based on the fact that particulate mass loading in some boilers tended to increase, but not significantly, and the consequences appeared to be relatively minor. Particulate emission results reported in the Phase I report (3) covering tests completed in the earlier stages of this contract again noted a tendency, in some cases, toward increased particulate emissions with "low NO_x" firing but concluded that any increases or decreases in dust loadings observed did not appear to be significant. Particulate emission data developed in tests during the last phase of this contract on two coal fired and one oil fired boiler are presented in Table 3-8, 3-9 and 3-10. Referring to Table 3-8, it may be seen that there are no significant differences in particulate mass emissions between "low NO_x" and baseline operating conditions. Where differences exist, they are minimal in magnitude and no appreciable effect on electrostatic precipitator collection efficiency or performance would be expected due to changes in particulate mass emissions.

Another potential side effect of low NO_x operation may be an increase in carbon on flyash or other unburned combustibles. As discussed above, staging the combustion process and decreasing excess air levels produces longer, "lazier" flames with increased tendencies toward incomplete combustion. Any increase in unburned carbon as a consequence of low NO_x combustion modifications, would have a corresponding adverse effect on boiler efficiency and might tend to increase particulate loading emitted from the boiler. An assessment of the magnitude of this potential side effect may be made based on the data of Table 3-8 by comparing the percent carbon on the particulate measured under baseline and low NO_x operations, respectively. Referring to Table 3-8, it may be seen that carbon losses are higher for "low NO_x" operation on East Kentucky Power Cooperative's No. 2 boiler at the Cooper station and on Gulf Power Company's No. 7 boiler at the Crist station, both of which are pulverized coal fired. The magnitude of these losses, however, even for "low NO_x" firing, is lower than other emission data obtained in prior studies (2), (3), and the consequences of these losses is diminished accordingly. It may also be noted from Table 3-8 that increases in carbon losses do not have a corresponding effect on particulate mass emissions, attesting to the relative unimportance of this effect. It should also be borne in mind that information developed in prior studies (2), (3) showed that carbon losses do not always increase as a result of "low NO_x" operating conditions.

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TABLE 3-8
PARTICULATE EMISSION TEST RESULTS

Utility	Test No.	Date	Firing Condition	Load, MW	Emissions			Req. Eff. To Meet 0.1 Lb/10 ⁶ Btu	Carbon On Particulate %	Coal Ash, %	HHV, Wet Cal/lb Btu/lb
					mg/m ³	GR/SCF	ng/J				
East Kentucky Power Cooperative, Inc., Cooper Station, Boiler No. 2	41	3/9/77	Base*	178	1.06	4.65	3280	7.63	1.48	12.78	11.742
	43	3/11/77	Base*	155	.72	3.12	2361	5.49	.94	12.48	12.217
	59	3/25/77	Low NO _x *	123	.78	3.41	2520	5.86	1.81	11.30	12.312
	60	3/28/77	Low NO _x *	123	.87	3.82	3130	7.28	1.87	10.47	12.291
Public Service Electric & Gas Company	4D	9/17/76	Base**	288	.0059	.026	17.2	0.04	-	-	-
	6C	9/17/76	Low NO _x **	280	.0063	.0274	17.2	0.04	-	-	-
Gulf Power Company, Crist Station, Boiler No. 7	150	6/20/78	Base*	436	.686	3.00	2301	5.35	-	-	-
	151	6/21/78	Low NO _x *	432	.874	3.82	1926	4.48	2.98	12.45	11.263
	152	6/22/78	Base*	417	.864	3.78	2881	6.70	0.87	16.48	10.782
	153	6/23/78	Low NO _x *	434	.909	3.97	2468	5.74	1.71	14.32	11.033

*Pulverised coal derived.
**Oil firing.

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TABLE 3-9

PARTICLE SIZE DISTRIBUTION, WT%

EAST KENTUCKY POWER COOPERATIVE
COOPER STATION - BOILER NO. 2

PULVERIZED COAL FIRING

Size Range	Baseline Firing			LOW NO _x Firing		
	Test No. 41	Test No. 43	Average	Test No. 59	Test No. 60	Average
>2.5	98.86	92.68	95.8	95.65	91.75	93.7
2.5	2.04	3.71	2.9	3.28	5.34	4.3
1.5	0.50	1.24	0.9	0.78	1.32	1.1
1.0	0.41	0.95	0.7	0.61	1.07	0.8
0.5	0.63	1.13	0.9	1.04	1.65	1.4
<0.5	0.36	0.62	0.5	0.67	1.11	0.9

TABLE 3-10
PARTICLE SIZE DISTRIBUTION, WT%
 GULF POWER COMPANY
 CRIST STATION - BOILER NO. 7
PULVERIZED COAL FIRING

Size Range	Baseline Firing			LOW NO _x Firing		
	Test No. 150	Test No. 152	Average	Test No. 151	Test No. 153	Average
>2.5	93.10	94.00	93.6	92.50	89.80	91.2
2.5	2.15	3.48	2.8	3.15	3.68	3.4
1.5	0.90	0.72	0.8	1.12	1.94	1.5
1.0	0.83	0.84	0.8	0.83	1.43	1.1
0.5	1.24	1.20	1.2	1.16	1.84	1.5
<0.5	1.80	1.72	1.3	1.24	1.33	1.3

Potential changes in particle size distribution that could result from low NO_x combustion modifications were also assessed in this study. Changes in size distribution of flue gas particulates could affect electrostatic precipitator collection efficiency, especially if these changes occur in the smaller size (fine) fractions. The data developed in this program were obtained upstream of the electrostatic precipitators (or mechanical dust collectors) using a Brink multi-stage cascade impactor incorporated in an EPA type sampling train between the cyclone and the filter as discussed above. A separate pump and flow rate measuring device was used to pull samples through the Brink impactor. This arrangement permitted simultaneous sampling for mass loading and particle size distribution determination at the required rates in isokinetic traverses of the boiler flue gas ducts, with the Brink equipment located outside of the boiler. Thus, the proper recommended flow rates were obtained in the Brink impactor to obtain the specified aerodynamic diameter cut points. The Brink impactor consists of five stages, each having cut points at rated conditions at diameters of 2.5, 1.5, 1.0, 0.5 and 0.25 μm followed by a final filter.

Particle size distribution measurement results obtained in this program are summarized in Tables 3-9 and 3-10. The data include all of the material collected in the probe and the cyclone for the size range greater than 2.5 μm . Comparing the data in Tables 3-9 and 3-10, it may be seen that there are no significant differences in particle size distribution between low NO_x and baseline operation for the boilers tested. These data parallel and are very similar to the particle size distribution data developed in previous tests (2). Since no significant differences in particle size distribution measurements occurred between data developed under baseline vs. "low NO_x " firing conditions, especially in the smaller size fractions, the conclusion reached, at least for these tests, is that combustion modifications for NO_x emission control should not materially affect electrostatic precipitator or mechanical collector performance. More data would obviously be helpful, however, to further support this conclusion.

The sampling arrangement used for obtaining particulate particle size distribution information employed the cyclone of the EPA train as the first cut point ahead of the Brink impactor. It is generally accepted that this device collects all material greater than 7 μm in diameter. The fractionation size (D_{50}) for each of the Brink impactor stages is the particle size (aerodynamic diameter in μm) collected with 50% efficiency by the impactor stage. For the Brink impactor the aerodynamic diameter (D_{50}) for each stage is as noted above when operated at the prescribed flow rates.

Figures 3-18 and 3-19 present particle size distribution data vs. aerodynamic diameter as a function of solids loading in cumulative percent below the stated size for East Kentucky Power Cooperative's Cooper No. 2 boiler and Gulf Power Company's Crist Station, No. 7

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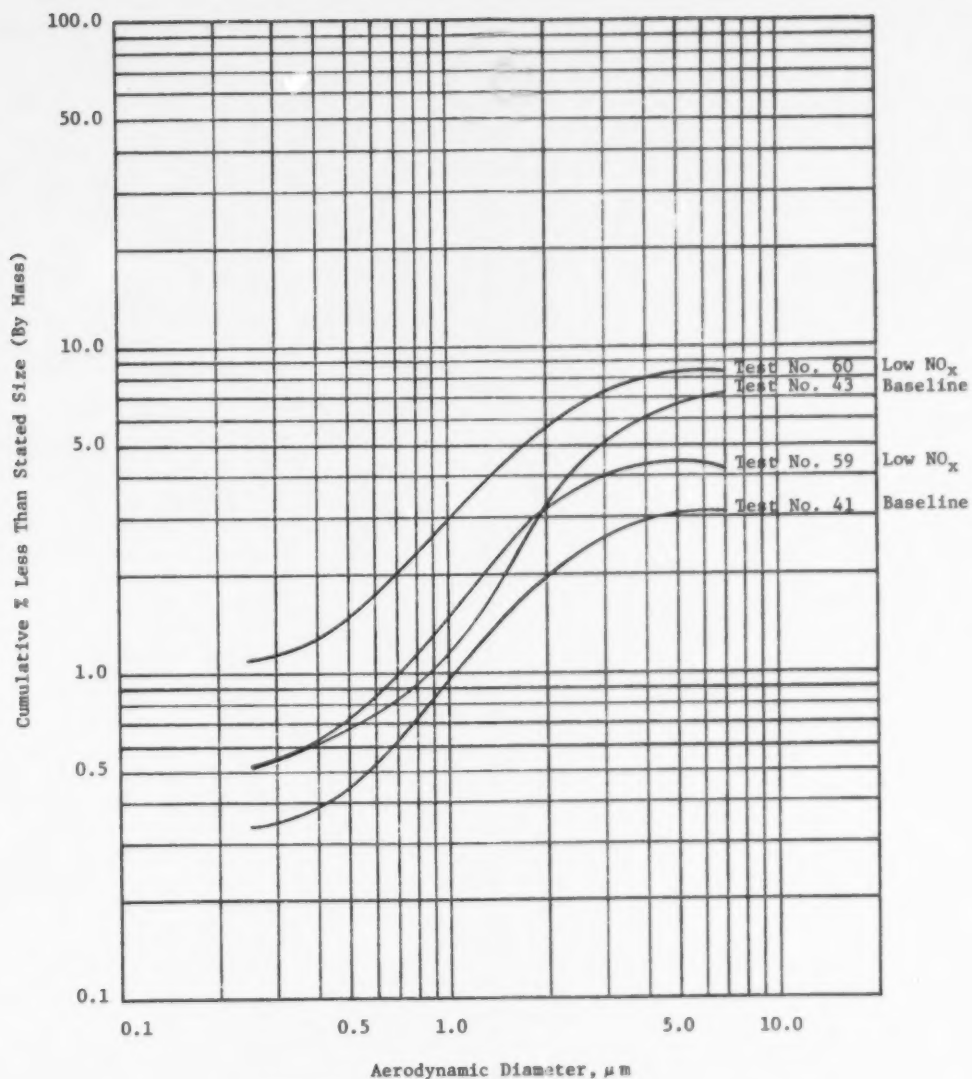


Figure 3-18. East Kentucky Power Cooperative, Inc.
Cooper Station No. 2.

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EPA Form 2350-4 (4-80)

(PREVIOUSLY C.N. EPA FORM 2351)

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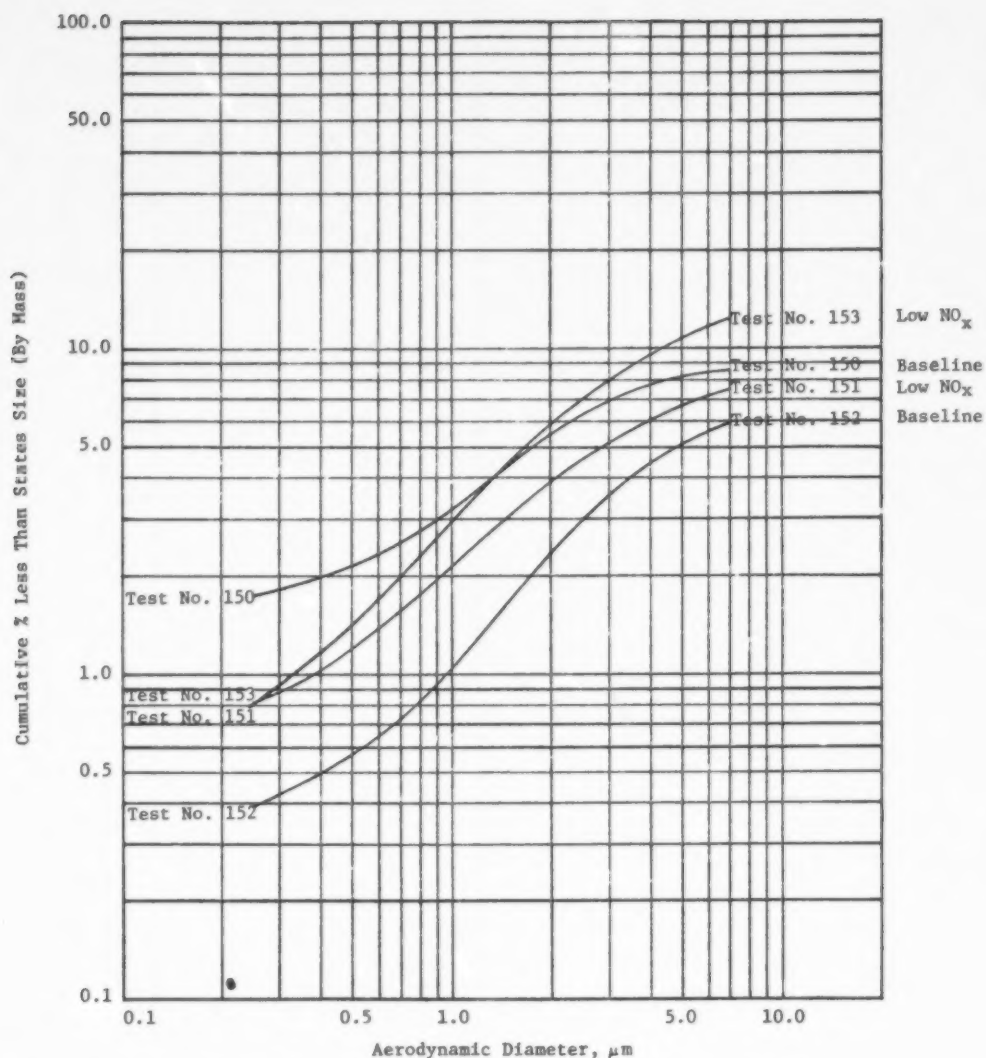


Figure 3-19. Gulf Power Company, Crist Station No. 7 Boiler.

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boiler. It should be noted that particulate test runs on these boilers were conducted at less than full load conditions. However, the effect on particulate mass loading and size distribution on a standard cubic foot basis should not be materially affected.

Referring to the curves shown in Figures 3-18 and 3-19, the data plotted for baseline and "low NO_x" operation exhibit relatively consistent trends with no indication of adverse side effects attributable to "low NO_x" combustion modifications. Although some scatter of data is indicated in the smaller size fractions, the range of these variations is not great and the results appear to be within the limits of this type of testing. These data are also consistent with and compare favorably to particle size distribution data developed in prior studies (3) during the earlier phase of this contract.

3.3 Furnace Tube Corrosion Investigations

Principal combustion modification techniques used to reduce nitrogen oxide emissions in boilers, such as staging the combustion process and reducing excess air levels used for combustion, can produce a net reducing environment in the lower region of the furnace, especially in the burner area. Concern has been expressed that this effect potentially may increase the corrosion rate in the tubes forming the walls of the furnace since high tube wastage was experienced in furnace tubes in areas of local reducing environments during the early days of the development of pulverized coal firing for utility boilers.

In early studies conducted by Exxon Research and Engineering Company under EPA sponsorship (2), corrosion rate data were developed using corrosion probes inserted through the walls of the furnace into the most corrosion vulnerable areas of the furnace. In these prior studies, corrosion conditions were deliberately accelerated and coupon corrosion rates obtained in 300-hour tests averaged approximately 50 mils per year with considerable scatter between high and low values. These high rates were the result of the higher than normal exposure temperature of 742 K (875°F) and the mild acid pickling of the coupons prior to exposure.

In the current program, part of which was reported in the Phase I report (3) and the remainder in this, the Phase II report, significant changes were made in the conditions for measuring corrosion rates in order to better relate rates obtained on probes to actual furnace wall tube corrosion rates. Coupon temperatures were controlled at temperatures approximating those of the furnace wall tubes, 603-658 K, (625-725°F) and the acid pickling procedure was eliminated. As a result, the corrosion rates measured were generally lower and more consistent for each boiler than the previous data. Other test conditions were kept the same as in the previous program, i.e., probes were inserted through openings in the furnace wall as close as possible to vulnerable furnace areas and exposure was maintained at approximately 300 hours. The analytical procedures used were also the same in both programs. Thus, each coupon was visually inspected after exposure and was photographed to record its appearance. Scale was then removed from the outside diameter surfaces by dry honing with glass beads under low pressure. The coupon was then weighed to obtain the weight loss from the outside surface. This was followed by dry honing of the inside diameter surface scale after which the coupon was reweighed to determine the weight loss from the inside surfaces. Corrosion rates were then calculated as the loss in mils per year (m/yr) using the weight loss data, the combined exposed coupon areas, the metal and scale densities, and the exposure time.

The corrosion rate data reported in the Phase I report (3) of the present program (300 hour exposure) were reasonably consistent, ranging in value from 6 mils/year to around 40 mils/year, averaging about 19 mils/year. Compared to the 50 mil/year average corrosion rate

obtained in the earlier study for 300-hour exposure under accelerated conditions, these rates are considerably lower, reflecting the attempt to approximate actual furnace wall tube conditions. These rates, however, are still an order of magnitude greater than the 1 to 3 mil/year wastage experienced in furnace waterwall tubes under normal firing conditions and corrosion probe results, accordingly, must be considered only as a relative measure of corrosion tendency. However, since corrosion rate data obtained via probes are easier and much less costly to develop than from actual field experience, the objective in subsequent studies is to continue probe measurements for eventual correlation with corrosion rate data obtained by measurement of actual furnace tube wastage.

This report presents corrosion rate data obtained with probes in tests on two additional boilers included in the current contract. Tables 3-11 and 3-12 cover data obtained on East Kentucky Power Cooperative's, No. 2 boiler at their Cooper Station in Burnside, Kentucky. As in previous tests, these data were developed at approximately 300-hour exposure time (under simulated normal conditions). Referring to the tables it may be seen that corrosion rates were again consistent, ranging in value from 6.6 to 29.9 mils/year and averaging 12.1 mils/year for all probes and conditions. Low NO_x conditions again showed higher corrosion rates than for baseline operation but not of significant implication, similar to results obtained in prior investigations.

Corrosion probe testing on the No. 7 boiler at Gulf Power Company's Crist Station was amplified extensively in order to obtain information on the effect of corrosion with time for potential correlation with actual furnace tube corrosion rate data under development on this unit in a long-term corrosion test. Conditions of exposure were maintained the same as in prior tests simulating actual furnace tube environment, but probe exposure of approximately 30 hours, 300 hours and up to 1000 hours were employed under both baseline and low NO_x conditions to determine initial, intermediate, and longer term corrosion effects. In addition, special ports were installed in the furnace for the installation of the probes in the most desirable areas. Two of these ports were located in the middle of the sidewalls within the burner zone (elevation 129.8 ft) in the most corrosion prone area and two others were located at the middle of the sidewalls but in the upper furnace area (elevation 157.8 ft) outside of the expected corrosion area, in order to provide "control" data.

TABLE 3-11

CORROSION RATE DATA

EAST KENTUCKY POWER COOPERATIVE, INC.
COOPER STATION, BOILER NO. 2

Probe No.	Location	Firing Condition	Exposure Time, Hrs.	Coupon Corrosion Rate	
				Mils./Year	Average
4	Left Side of Rear Wall, 10' Below Bottom Burner Level	Baseline	288	6.6(1)	8.4
				9.1	
				9.4	
3	Right Side of Rear Wall, 10' Below Bottom Burner Level	Low NO _x (2)	285	14.8(1)	19.2
				12.9	
				29.9	
4	Left Side of Rear Wall 10' Below Bottom Burner Level	Low NO _x	282	8.2(1)	11.4
				9.8	
				16.3	

NOTES:

(1) Coupon closest to furnace wall

(2) No. 3 probe exposed to baseline conditions was lost in the furnace

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TABLE 3-12

CORROSION RATE DATA

EAST KENTUCKY POWER COOPERATIVE, INC.
COOPER STATION, NO. 2 BOILER

Probe No.	Location	Firing Condition	Exposure Time, Hrs.	Coupon Corrosion Rate	
				Mils/Year	Average
1	Left Side of Rear Wall 8' Below Top Burner Level	Base	288	7.5(1)	7.6
				8.4	
				7.0	
2	Right Side of Rear Wall 8' Below Top Burner Level	Base	287	12.9(1)	10.1
				9.8	
				7.7	
2	Right Side of Rear Wall 8' Below Top Burner Level	Low NO _x	283	17.7(1)	15.6
				17.1	
				12.1	

NOTES:

(1) Coupon closest to furnace wall.

Corrosion rate data developed on the No. 7 boiler at the Crist Station under varying exposure times are given in Tables 3-13 through 3-20. As expected, initial corrosion rate data, obtained in 24 to 30 hour exposure tests are considerably higher than for 300 hour or longer exposure periods. In these short term tests (Tables 3-13, 3-14 & 3-15), average corrosion rates varied from 62.9 to 113.6 mils per year. Under low NO_x conditions (Table 3-13) probes exposed for 24 to 30 hours in the expected high corrosion area of the furnace at the burner levels (129.8 ft) experienced greater corrosion than probes located outside of the burner areas (157.8 ft), i.e., 113.6 vs. 90.8 mils/year, average, respectively. A similar trend is evident under baseline conditions, especially as exhibited in Table 3-15, but the differences are far less pronounced or significant.

Corrosion rate data developed in probe exposures ranging from 182 to 294.3 hours are listed in Tables 3-16 through 3-18. As in previous tests, corrosion rates are relatively low (overall average of 22.7 mils/year) and quite consistent. Referring to Table 3-16 for baseline operation, it may be seen that the average corrosion rate was 26.5 mils/year. For low NO_x firing (Table 3-17) corrosion averaged 20.4 mils/year or lower than for baseline. These differences are not viewed as being of particular importance. For baseline operation (Table 3-16), probes in the more vulnerable burner area (129.8') averaged 17.1 mils/year vs. 25.9 mils/year for those at the upper level of 157.8 ft. Under low NO_x conditions (Table 3-16), however, differences are much greater, i.e., 24.4 vs. 16.4 mils/year for probes at the 129.8' and 157.8' levels, respectively. While the magnitude of the latter differences are significant, it is doubtful that much importance should be attached to them since data developed in longer term tests (discussed below) show no appreciable differences.

Data tabulated in Table 3-18 were obtained with probes inserted in slag blower openings in the boiler sidewalls at a location 2 1/2 ft. above the top burner centerline. Conditions at this location would be expected to approximate those at 129.8 ft. elevation and results obtained are, in fact, comparable.

Tables 3-19 and 3-20 present corrosion rate data developed in longer-term tests ranging from 597 to 999 hours. Referring to the tables it may be noted that average corrosion rates are significantly lower and more consistent than for probes exposed at 30 to 300 hours and location of the probes within the boiler does not appear to be a factor. Also, average corrosion rates for probes exposed to baseline firing conditions for approximately 1000 hours, ranging between 8.0 and 15.6 mils/year, are comparable to rates of 13.3 and 9.5 mils/year average developed on probes exposed to low NO_x operating conditions for 597 and 738 hours exposure, respectively.

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TABLE 3-13
CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

<u>Probe No.</u>	<u>Location</u>	<u>Firing Condition</u>	<u>Exposure Time, Hrs.</u>	<u>Coupon Corrosion Rate</u>	
				<u>Mils/Year</u>	<u>Average</u>
1	Right Wall (129.8')	Low NO _x	24	136.2 91.0(1)	113.6
2	Right Wall (157.8')	Low NO _x	24	68.1 110.4	89.3
4	Left Wall (157.8')	Low NO _x	24	87.5 97.1	92.3

Note:

(1) Coupon closest to furnace wall

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TABLE 3-14
CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

<u>Probe No.</u>	<u>Location</u>	<u>Firing Condition</u>	<u>Exposure Time, Hrs.</u>	<u>Coupon Corrosion Rate Mils/Year</u>	<u>Average</u>
1	Right Wall (129.8')	Baseline	25	80.2(1) 53.6 82.7	72.1
2	Right Wall (157.8')	Baseline	25	75.2(1) 56.4 57.0	62.9
4	Left Wall (157.8')	Baseline	25	116.4(1) 85.0 73.3	91.6

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TABLE 3-15

CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

<u>Probe No.</u>	<u>Location</u>	<u>Firing Condition</u>	<u>Exposure Time, Hrs.</u>	<u>Coupon Corrosion Rate Mils/Year</u>	<u>Average</u>
2	Right Wall (157.8')	Baseline	29.8	108.9(1) 116.9 51.3	92.4
4	Left Wall (129.8')	Baseline	30.0	100.5(1) 59.9 161.6	107.3

Note:

(1) Coupon closest to furnace wall.

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TABLE 3-16
CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

<u>Probe No.</u>	<u>Location</u>	<u>Firing Condition</u>	<u>Exposure Time, Hrs.</u>	<u>Coupon Corrosion Rate Mils/Year</u>	<u>Average</u>
1	Right Wall (129.8')	Baseline	294.3	47.4 9.1 12.6(1)	23.0
2	Right Wall (157.8')	Baseline	291.8	9.7 5.3 11.7(1)	8.9
3	Left Wall (129.8')	Baseline	293.2	46.3 27.9 19.3(1)	31.2
4	Left Wall (157.8')	Baseline	289.3	88.0 21.5 19.5(1)	43.0
					26.5 Avg.

(1) Coupons closest to furnace wall

TABLE 3-17

CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

Probe No.	Location	Firing Condition	Exposure Time, Hrs.	Coupon Corrosion Rate	
				Mils/Year	Average
1	Right Wall (129.8')	Low NO _x	256.0	31.9(1)	32.1
				33.5	
				31.0	
2	Right Wall (157.8')	Low NO _x	261.1	25.8(1)	21.6
				22.0	
				17.0	
E	Right Wall (129.8')	Low NO _x	182.0	14.3(1)	16.7
				15.2	
				20.6	
4	Left Wall (157.8')	Low NO _x	261.2	17.8(1)	<u>11.1</u>
				7.6	
				7.9	
					20.4 Avg.

Note:

(1) Coupon closest to furnace wall

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TABLE 3-18
CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

<u>Probe No.</u>	<u>Location(2)</u>	<u>Firing Condition</u>	<u>Exposure Time, Hrs.</u>	<u>Coupon Corrosion Rate Mils/Year</u>	<u>Average</u>
1	Left Wall	Baseline	286	25.7(1) 20.8 32.6	26.4
2	Left Wall	Low NO _x	288	11.6(1) 10.2 16.8	12.9

Notes:

(1) Coupon closest to furnace wall.

(2) Probes located in side walls 2 1/2 feet above top burner centerline.

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TABLE 3-19
CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

<u>Probe No.</u>	<u>Location</u>	<u>Firing Condition</u>	<u>Exposure Time, Hrs.</u>	<u>Coupon Corrosion Rate Mils/Year</u>	<u>Average</u>
C	Left Wall (157.8')	Low NO _x	597	9.3(1) 11.7 18.9	13.3
A	Right Wall (157.8')	Low NO _x	738	8.3(1) 9.3 11.0	9.5

Note:

(1) Coupon closest to furnace wall.

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TABLE 3-20
CORROSION RATE DATA
GULF POWER COMPANY, CRIST STATION, BOILER NO. 7
PULVERIZED COAL FIRING

<u>Probe No.</u>	<u>Location</u>	<u>Firing Condition</u>	<u>Exposure Time, Hrs.</u>	<u>Coupon Corrosion Rate Mils/Year</u>	<u>Average</u>
2	Right Wall (157.8')	Baseline	996.5	10.2(1)	8.0
				7.9	
				5.9	
3	Left Wall (129.8')	Baseline	999.0	15.8	12.1
				11.4	
				9.1(1)	
4	Left Wall (157.8')	Baseline	997.2	15.9(1)	15.6
				15.1	
				15.9	

A comparison of corrosion rate data developed in this program on Gulf Power Company's No. 7 boiler at the Crist Station is better illustrated in Figure 3-20 showing a plot of corrosion rate vs. exposure time for probes exposed to both baseline and low NO_x firing conditions. Referring to Figure 3-20 it may be noted that coupon corrosion rates decrease with exposure time asymptotically up to 1000-hour exposure. Initial corrosion rates developed at 24 to 30-hours exposure are high with considerable scatter in the data. At 250 to 300 hours exposure, corrosion rates are much lower and more consistent in range. Above 450 to 500 hours exposure, corrosion rates level out to an average rate of 10 to 12 mils/year with very little scatter in the range of the data. These rates, however, are still much higher than the 1 to 3 mil/year wastage expected in actual furnace wall tubes. It is apparent from Figure 3-20 that corrosion probes should be exposed for a minimum of 450 hours if effective correlation is to be made with actual furnace tube corrosion.

It is concluded from these corrosion probe investigations that:

- Corrosion rates developed via corrosion probes decrease with exposure time through 1000 hours approaching an asymptote above 450 hours exposure.
- Corrosion probes exposed for short terms (up to 30 hours) within the burner areas in the furnace sidewalls experience significantly greater corrosion rates than probes exposed outside the burner levels under both baseline and low NO_x firing conditions. However, more data is needed to reach firm conclusions.
- Probes exposed for periods of 300 to 1000 hours experienced no significant differences in corrosion rates due to furnace location (burner vs. nonburner area) or furnace operating mode (baseline vs. low NO_x firing).
- Effective correlation of actual long-term furnace tube corrosion rates require corrosion probe exposure of a minimum of 450 hour exposure.

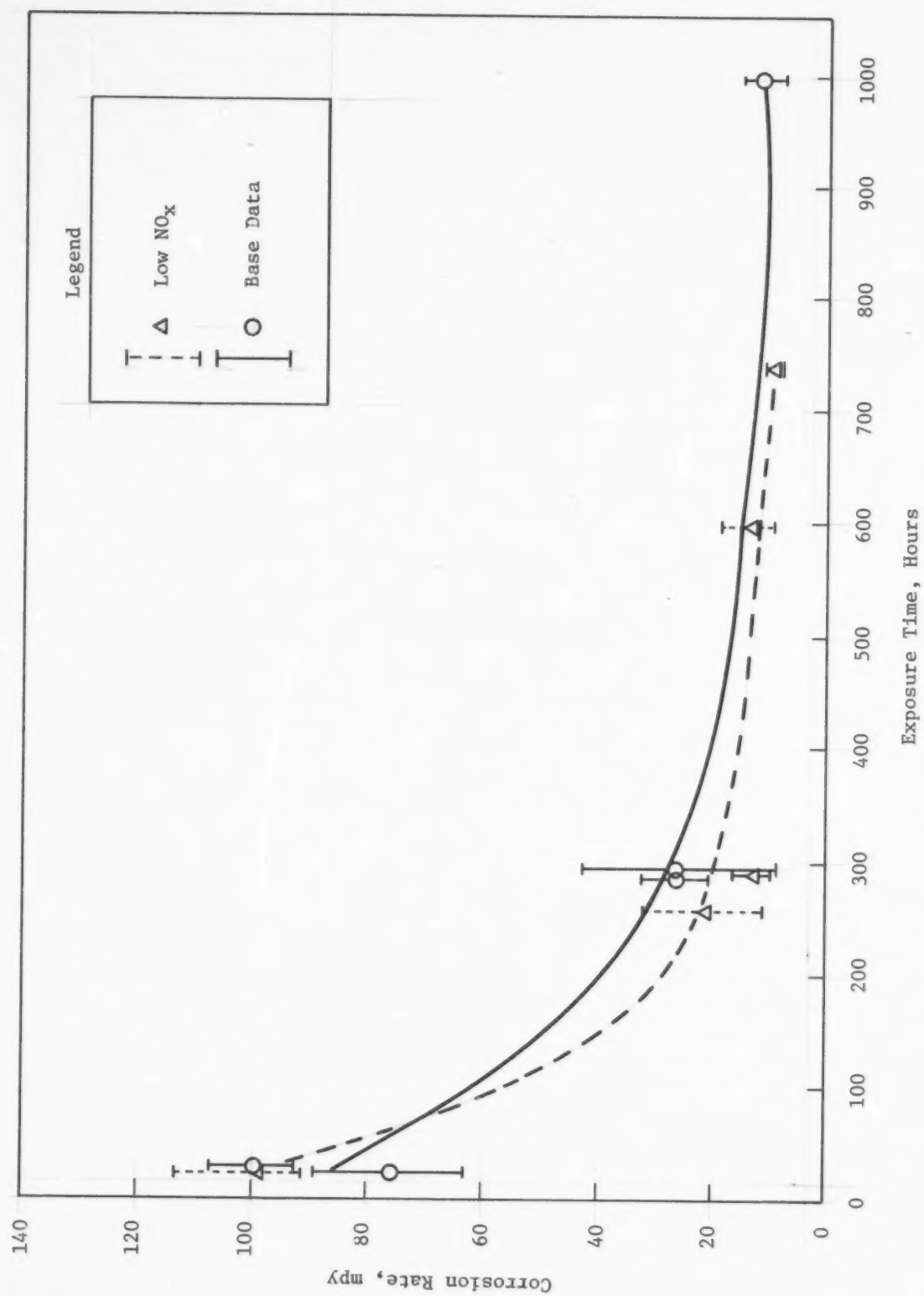


Figure 3-20. Comparison of Corrosion Rates
Gulf Power Company, Crist Station, Boiler No. 7
Pulverized Coal Firing.

3.4 Sulfur Oxides Emission Results

An Exxon Research and Engineering Company modification of EPA Method No. 6 was used for wet chemical analysis of flue gas samples for sulfur oxides (SO_2 and SO_3) determination. Samples were taken from the boiler ducts at the same point where other gaseous emission samples were extracted for continuous analysis in the Exxon Research analytical van. Invariably this sampling point was located at the boiler outlet downstream of the economizer but upstream of the regenerative airheaters, in order to eliminate dilution problems due to air leakage inherent in this type of airheater. Flue gas samples for sulfur oxides analysis were drawn from the ducts through a heated probe and passed through a series of absorbers. The first absorber, containing an 80% solution of isopropanol, absorbed the sulfur trioxide and the second, containing a 3% hydrogen peroxide solution, absorbed the sulfur dioxide. The amounts absorbed were determined titrimetrically using barium perchlorate as the titrant for the SO_3 solution with thorin as an indicator and sodium hydroxide as the titrant and methyl-orange as an indicator for the SO_2 solution.

The Phase I Report (3), presented data on sulfur oxides wet chemical analyses for boilers tested in the earlier phase of the current contract and concluded that the results obtained were in line with expectations for the boilers tested. Tables 3-21, 3-22, 3-23 and 3-24 in this, the Phase II report, tabulate the results of additional wet chemical analyses obtained on the remaining boilers tested in the latter phases of this contract. It should be recognized that the sulfur dioxide content of the flue gases in any combustion installation is directly related to the sulfur content of the fuel burned. The sulfur trioxide content, however, may vary depending on operating conditions affecting the conversion of SO_2 to SO_3 . Another factor affecting the quantity of sulfur oxides in the flue gases is the retention (or loss) of some of the sulfur within the combustion system. The ash content of the fuel and its chemical composition is also of great importance in this process. Invariably sulfur oxide emission concentrations calculated on the assumption of 100% conversion of the sulfur content of the fuels burned are always higher than measured sulfur oxides concentrations. This is not unexpected, especially in pulverized coal fired boilers. In the dry bottom pulverized coal fired boilers tested, 15 to 20 percent of the fuel ash is extracted from the furnace as bottom ash and the remaining 80 to 85 percent is carried out of the boiler with the flue gases to electrostatic precipitators (or other collection devices) which collect 98 to 99 percent of the fly ash. Some of the fuel ash remains in the boiler as slag on the furnace walls or deposits in the convection sections and hoppers. A portion of the fuel sulfur content, in each case, may remain with these ash accumulations to decrease the total amount emitted as SO_2 or SO_3 in the flue gases. Only limited sulfur balance data are available but it may be expected that from 5 to 25 percent of the fuel sulfur may be retained in a boiler, especially where a boiler is fired with a high calcium content coal.

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TABLE 3-21
EAST KENTUCKY POWER COOPERATIVE
COOPER STATION, BOILER NO. 2
WET CHEMISTRY SO₂/SO₃ ANALYSES WET CHEMISTRY ANALYSIS
PULVERIZED COAL FIRING

Date	Test No.	Firing Condition	Load MW	O ₂ , %	SO ₂ ng/J	PPM	SO ₃ ng/J	PPM	SO ₃ /SO ₂ Ratio, %
*2/28/77	37	Baseline	218	2.5	1434	1798	18	18	1.0
*3/28/77	60	Low NO _x	123	6.5	1452	1820	22	22	1.2
4/15/77	75	Low NO _x	190	2.6	1251	1568	16	16	1.0
4/15/77	76	Baseline	205	2.4	1207	1514	21	21	1.4
4/19/77	77	Baseline	205	2.6	1026	1286	33	33	2.6
4/19/77	78	Low NO _x	203	2.7	878	1101	-	-	-
4/20/77	79	Baseline	204	2.7	751	941	22	22	2.3

* Fuel Sulfur levels were measured as follows: 2.09% (Test 37); 2.13% (Test 60)

TABLE 3-22

PUBLIC SERVICE COMPANY OF COLORADO

COMANCHE STATION, BOILER NO. 2

WET CHEMISTRY SO₂/SO₃ ANALYSES

PULVERIZED COAL FIRING

Date	Test No.	Firing Condition	Load MW	O ₂ , %	Calculated SO _x /PPM	Wet Chemistry Analyses			SO ₃ /SO ₂ Ratio, %
						SO ₂ ng/J	SO ₃ ppm	SO ₃ ng/J	
5/31/77	1	Low NO _x	350	4.6	437	260	326	1	0.3
6/1/77	6	Low NO _x	355	4.5	-	363	455	4	0.9
6/2/77	9	Baseline	354	5.7	417	213	267	-	-
6/3/77	11	Baseline	274	5.4	-	207	260	3	1.2
6/7/77	14	Low NO _x	348	4.8	335	151	189	1	0.5
6/7/77	14	Low NO _x	348	4.8	335	149	187	13	7.0
6/7/77	14A	Low NO _x	348	4.7	335	177	222	10	4.5
6/9/77	15	Low NO _x	354	4.8	368	239	300	9	3.0
6/9/77	15	Low NO _x	354	4.8	368	258	323	8	0.9
6/9/77	15A	Low NO _x	350	5.6	368	207	260	9	3.5
6/9/77	15B	Low NO _x	350	5.6	368	250	314	7	2.2

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TABLE 3-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SEWAREN STATION - BOILER NO. 5

OIL FIRING

SO₂ & SO₃ Content of Flue Gas

	<u>Base</u>	<u>Low NO_x*</u>
SO ₂ As Measured	197	188
SO ₃ " "	7.3	6.3
O ₂ , %	2.2	1.85
Load, MW (Gross)	285	284

*Top wing burners on air only.

Some of the tables mentioned above afford a comparison of calculated SO_x values, based on 100% emissions, with measured experimental data. Table 3-22 listing data for the No. 2 boiler at the Comanche Station of the Public Service Company of Colorado is a case in point. Sulfur balance tests conducted on this boiler concluded that 25 percent of the sulfur in the coal failed to show up as SO_2 in the stack. Comparing the calculated SO_x values to measured values, it may be seen that the results are reasonably in accord with expectations. Similar conclusions may be drawn from a comparison of the data for the Crist Station (No. 7 boiler) listed in Table 3-23.

Sulfur trioxide measurements for these tests ranged from 1 to 77 ppm. As expected, where low sulfur fuels are fired such as the low sulfur coal (~0.5%) fired at the Comanche Station (Table 3-22) and the low sulfur fuel oil (<0.3%) burned at the Sewaren station (Table 3-24), sulfur oxides concentrations are also low. SO_3 concentrations varied from 1 to 13 ppm and 6 to 7 ppm in these boilers, respectively, compared to a range of 16 to 33 ppm and 12 to 77 ppm for the higher sulfur coals fired at the Cooper Station (Table 3-21) and Crist Station (Table 3-23). Referring to the tables it may also be noted that no significant differences appear in SO_x measured values between baseline and low NO_x firing conditions as might be expected in some installations under low excess air firing conditions. Also, as indicated in the tables, SO_3 measurements are within the anticipated range of five percent of total SO_x in the flue gases affirming confidence in the data.

3.5 Effect of Combustion Modification on Boiler Performance

Side effects of "low NO_x " combustion modifications on boiler performance were investigated and evaluated for each major test. Control room board data and other pertinent information were recorded for baseline and optimum "low NO_x " firing conditions and boiler efficiency was calculated in accordance with the ASME Steam Generating Units, Power Test Codes using the Abbreviated Efficiency Test, heat loss method. Calculations were based on the assumption that combustibles in the bottom ash slag were zero and unmeasured losses were 0.5 percent. Examples of typical performance data and the calculations made are shown in the ASME test forms in Tables 3-25 and 3-26.

Low NO_x combustion modifications result in longer, lazier, less intense combustion conditions. The effect is a tendency toward increased unburned combustibles which potentially may lower boiler efficiency. Earlier field studies (2) indicated some increased combustible losses under "low NO_x " combustion modifications but concluded that only negligible differences in boiler efficiency occurred due to this type of operation. Investigations conducted during the early phase of this contract, reported in the Phase I report (3), indicated that no significant decreases in boiler efficiency occurred as a result of "low NO_x " operation; in fact, in some cases small increases were calculated. During the latter stages of this contract boiler performance information (covered in this report) was obtained on the No. 2 boiler at the Cooper Station of the East Kentucky Power Cooperative, Inc. and at Gulf Power Company's, Crist Station, No. 7 boiler, both of which are pulverized coal fired. Table 3-27 tabulates the boiler efficiency calculated for each test along with other pertinent boiler performance information. Differences in calculated boiler efficiency between baseline and "low NO_x " tests provide a comparison of any adverse side effects due to "low NO_x " firing. Such comparisons, however, may be confounded by other factors affecting boiler efficiency such as, load, differences in coal quality (Btu, moisture, ash content, etc.), carbon content of the particulate (combustible losses), etc. In general, efficiency increases with load and decreases with deterioration in coal quality (lower Btu, increased moisture and ash content etc) and increased combustible losses.

Comparing the results tabulated in Table 3-27, it may be seen that the increased carbon content of the particulates resulting from "low NO_x " firing, is not reflected in corresponding decreases in boiler efficiency. Furthermore, there are no startling improvements or deterioration in boiler performance reflecting major adverse effects due to low NO_x combustion modifications. The minor differences in boiler efficiency exhibited between baseline and low NO_x operation may be explained by other factors affecting efficiency, as mentioned above. The overall conclusion from these data is that combustion modifications, at the levels practiced in these investigations for NO_x emission control, produced no significant adverse effects on boiler efficiency.

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TABLE 3-25

SUMMARY SHEET
ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST
PTC 4.1-a (1964)

OWNER OF PLANT		TEST NO. 1A		BOILER NO. 6		DATE 4-18-72	
TEST CONDUCTED BY		LOCATION		Widows Creek			
BOILER, MAKE & TYPE		Eesso Research & Engineering Co.		OBJECTIVE OF TEST		Boiler Performance Rating - Mrs.	
STOKER, TYPE & SIZE		B&W Radiant		RATED CAPACITY		125 MW	
PULVERIZER, TYPE & SIZE		Type E		BURNER, TYPE & SIZE			
FUEL USED		Bicuminous Coal		MINE		COUNTY	
PRESSURES & TEMPERATURES		STATE		SIZE AS FIRED			
1 STEAM PRESSURE IN BOILER DRUM		psia		COAL AS FIRED PROX. ANALYSIS		% wt	
2 STEAM PRESSURE AT S. H. OUTLET		psia		37 MOISTURE		5.4	
3 STEAM PRESSURE AT R. H. INLET		psia		38 VOL MATTER		52	
4 STEAM PRESSURE AT R. H. OUTLET		psia		39 FIXED CARBON		53	
5 STEAM TEMPERATURE AT S. H. OUTLET		F		40 ASH		44	
6 STEAM TEMPERATURE AT R. H. INLET		F		TOTAL		47	
7 STEAM TEMPERATURE AT R. H. OUTLET		F		41 Btu per lb AS FIRED		11452	
8 WATER TEMP. ENTERING (ECON.) (BOILER)		F		ASH SOFT TEMP. ASTM METHOD			
9 STEAM QUALITY & MOISTURE OR P. P. M.				COAL OR OIL AS FIRED ULTIMATE ANALYSIS		54	
10 AIR TEMP. AROUND BOILER (AMBIENT)		F		43 CARBON		67.27	
11 TEMP. AIR FOR COMBUSTION (THIS IS REFERENCE TEMPERATURE)		F		44 HYDROGEN		4.29	
12 TEMPERATURE OF FUEL		F		45 OXYGEN		56	
13 GAS TEMP. LEAVING (Boiler) (Econ.) (Air Mr.)		F		46 NITROGEN		57	
14 GAS TEMP. ENTERING AM (If conditions to be corrected, see instructions)		F		47 SULPHUR		0.77	
UNIT QUANTITIES				48 ASH		15.87	
15 ENTHALPY OF SAT. LIQUID (TOTAL HEAT)		Btu/lb		37 MOISTURE		61	
16 ENTHALPY OF (SATURATED) (SUPERHEATED) STM.		Btu/lb		TOTAL		TOTAL	
17 ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)		Btu/lb		COAL PULVERIZATION		TOTAL HYDROGEN % wt	
18 ENTHALPY OF REHEATED STEAM R. H. INLET		Btu/lb		48 GRINDABILITY INDEX*		42 DENSITY 68 F ATM. PRESS.	
19 ENTHALPY OF REHEATED STEAM R. H. OUTLET		Btu/lb		49 FINENESS % THRU 50 M*		43 Btu PER CU FT	
20 HEAT ABS/LB OF STEAM (ITEM 16 - ITEM 17)		Btu/lb		50 FINENESS % THRU 200 M*		41 Btu PER LB	
21 HEAT ABS/LB R. H. STEAM (ITEM 19 - ITEM 18)		Btu/lb		54 INPUT-OUTPUT EFFICIENCY OF UNIT %		ITEM 21 - 100 ITEM 20	
22 DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL		lb/lb		HEAT LOSS EFFICIENCY		Btu/lb A. P. FUEL	
23 Btu PER LB IN REFUSE (WEIGHTED AVERAGE)		Btu/lb		55 HEAT LOSS DUE TO DRY GAS		6.90	
24 CARBON BURNED PER LB AS FIRED FUEL		lb/lb		56 HEAT LOSS DUE TO MOISTURE IN FUEL		4.55	
25 DRY GAS PER LB AS FIRED FUEL BURNED		lb/lb		57 HEAT LOSS DUE TO H ₂ O FROM COMB. OF H ₂		3.95	
HOURLY QUANTITIES				58 HEAT LOSS DUE TO COMBUST. IN REFUSE		1.26	
26 ACTUAL WATER EVAPORATED		lb/hr		59 HEAT LOSS DUE TO RADIATION		6.002	
27 REHEAT STEAM FLOW		lb/hr		70 UNMEASURED LOSSES		0.5	
28 RATE OF FUEL FIRING (AS FIRED wt)		lb/hr		71 TOTAL		13.16	
29 TOTAL HEAT INPUT (Item 28 x Item 41) 1000		Btu/hr		72 EFFICIENCY = (100 - Item 71)		86.84	
30 HEAT OUTPUT IN BLOW-DOWN WATER		Btu/hr					
31 TOTAL HEAT OUTPUT (Item 26 + Item 28) + (Item 27 + Item 21) + Item 30 1000		Btu/hr					
FLUE GAS ANAL. (BOILER) (ECON.) (AIR NTR) OUTLET							
32 CO ₂		% VOL		14.44			
33 O ₂		% VOL		3.3			
34 CO		% VOL		0.64			
35 H ₂ (BY DIFFERENCE)		% VOL		82.36			
36 EXCESS AIR		%					

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

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TABLE 3-26

PTC 4.1-6 (1964)

CALCULATION SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

Revised September, 1965

OWNER OF PLANT	IVA	TEST NO. 1A	BOILER NO. 6	DATE 4-18-72
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20	HEAT OUTPUT IN BOILER SLOW-DOWN WATER = LB OF WATER SLOW-DOWN PER HR =	ITEM 15	ITEM 17	LB/hr
		1000		

If impractical to weigh refuse, this item can be estimated as follows:

24 DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\% \text{ ASH IN AS FIRED COAL}}{100 - \% \text{ COMB. IN REFUSE SAMPLE}}$

24	CARBON BURNED PER LB AS FIRED FUEL	ITEM 43	ITEM 23	ITEM 23	
		67.27	0.527	912.1	0.66
		100	14.500		

NOTE: IF FLUE DUST & ASH PY REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25	DRY GAS PER LB AS FIRED FUEL BURNED	$\frac{11\text{CO}_2 + 8\text{O}_2 + 7(\text{H}_2 + \text{CO})}{3\text{HCO}_2 + \text{CO}}$	=	LB CARBON BURNED PER LB AS FIRED FUEL	$\times \frac{1}{12}$
		ITEM 22	ITEM 23	ITEM 33	ITEM 34
		14.4	3.3	82.26	0.04
		3	14.4	0.04	
					11.6

26	EXCESS AIR	$\frac{\text{O}_2}{2} = \frac{\text{CO}}{2}$	ITEM 23	ITEM 34	
		$3.682\text{H}_2 - (\text{O}_2 - \frac{\text{CO}}{2})$			

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	LOSS %	LOSS %
--	----------------------	----------------------	--------	--------

45	HEAT LOSS DUE TO DRY GAS	LB DRY GAS PER LB AS FIRED FUEL	$\times C_p \times (T_{\text{gas}} - T_{\text{air}})$	ITEM 25	ITEM 13	ITEM 11	
				11.6	372	88	790
							790
							6.90

46	HEAT LOSS DUE TO MOISTURE IN FUEL	LB H ₂ O PER LB AS FIRED FUEL	$\times [(\text{ENTHALPY OF VAPOR AT 1 PSIA & T GAS}) - (\text{ENTHALPY OF LIQUID AT T AIR})]$	ITEM 27	ITEM 11		
				12.79			
							63.3
							63.3
							0.55

47	HEAT LOSS DUE TO H ₂ O FROM COMB. OF H ₂	$\times [(\text{ENTHALPY OF VAPOR AT 1 PSIA & T GAS}) - (\text{ENTHALPY OF LIQUID AT T AIR})]$	ITEM 22	ITEM 13	ITEM 11		
				4.29	122.79		
							452.5
							3.95

48	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE	ITEM 22	ITEM 23				
		0.587	912.1	144.8			
							1.26

49	HEAT LOSS DUE TO RADIATION	TOTAL BTU RADIATION LOSS PER HR	LB AS FIRED FUEL	ITEM 22			
							0.2
							0.002

70	UNMEASURED LOSSES						
							0.5

71	TOTAL						13.16
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72	EFFICIENCY = (100 - ITEM 71)						86.84
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Revised September 1965. Replaces ASME Form 312, 313, 314, 315, 316, 317, 318, 319, 320, 321, 322, 323, 324, 325, 326, 327, 328, 329, 330, 331, 332, 333, 334, 335, 336, 337, 338, 339, 340, 341, 342, 343, 344, 345, 346, 347, 348, 349, 350, 351, 352, 353, 354, 355, 356, 357, 358, 359, 360, 361, 362, 363, 364, 365, 366, 367, 368, 369, 370, 371, 372, 373, 374, 375, 376, 377, 378, 379, 380, 381, 382, 383, 384, 385, 386, 387, 388, 389, 390, 391, 392, 393, 394, 395, 396, 397, 398, 399, 400, 401, 402, 403, 404, 405, 406, 407, 408, 409, 410, 411, 412, 413, 414, 415, 416, 417, 418, 419, 420, 421, 422, 423, 424, 425, 426, 427, 428, 429, 430, 431, 432, 433, 434, 435, 436, 437, 438, 439, 440, 441, 442, 443, 444, 445, 446, 447, 448, 449, 450, 451, 452, 453, 454, 455, 456, 457, 458, 459, 460, 461, 462, 463, 464, 465, 466, 467, 468, 469, 470, 471, 472, 473, 474, 475, 476, 477, 478, 479, 480, 481, 482, 483, 484, 485, 486, 487, 488, 489, 490, 491, 492, 493, 494, 495, 496, 497, 498, 499, 500, 501, 502, 503, 504, 505, 506, 507, 508, 509, 510, 511, 512, 513, 514, 515, 516, 517, 518, 519, 520, 521, 522, 523, 524, 525, 526, 527, 528, 529, 530, 531, 532, 533, 534, 535, 536, 537, 538, 539, 540, 541, 542, 543, 544, 545, 546, 547, 548, 549, 550, 551, 552, 553, 554, 555, 556, 557, 558, 559, 560, 561, 562, 563, 564, 565, 566, 567, 568, 569, 570, 571, 572, 573, 574, 575, 576, 577, 578, 579, 580, 581, 582, 583, 584, 585, 586, 587, 588, 589, 590, 591, 592, 593, 594, 595, 596, 597, 598, 599, 600, 601, 602, 603, 604, 605, 606, 607, 608, 609, 610, 611, 612, 613, 614, 615, 616, 617, 618, 619, 620, 621, 622, 623, 624, 625, 626, 627, 628, 629, 630, 631, 632, 633, 634, 635, 636, 637, 638, 639, 640, 641, 642, 643, 644, 645, 646, 647, 648, 649, 650, 651, 652, 653, 654, 655, 656, 657, 658, 659, 660, 661, 662, 663, 664, 665, 666, 667, 668, 669, 670, 671, 672, 673, 674, 675, 676, 677, 678, 679, 680, 681, 682, 683, 684, 685, 686, 687, 688, 689, 690, 691, 692, 693, 694, 695, 696, 697, 698, 699, 700, 701, 702, 703, 704, 705, 706, 707, 708, 709, 710, 711, 712, 713, 714, 715, 716, 717, 718, 719, 720, 721, 722, 723, 724, 725, 726, 727, 728, 729, 730, 731, 732, 733, 734, 735, 736, 737, 738, 739, 740, 741, 742, 743, 744, 745, 746, 747, 748, 749, 750, 751, 752, 753, 754, 755, 756, 757, 758, 759, 760, 761, 762, 763, 764, 765, 766, 767, 768, 769, 770, 771, 772, 773, 774, 775, 776, 777, 778, 779, 780, 781, 782, 783, 784, 785, 786, 787, 788, 789, 790, 791, 792, 793, 794, 795, 796, 797, 798, 799, 800, 801, 802, 803, 804, 805, 806, 807, 808, 809, 810, 811, 812, 813, 814, 815, 816, 817, 818, 819, 820, 821, 822, 823, 824, 825, 826, 827, 828, 829, 830, 831, 832, 833, 834, 835, 836, 837, 838, 839, 840, 841, 842, 843, 844, 845, 846, 847, 848, 849, 850, 851, 852, 853, 854, 855, 856, 857, 858, 859, 860, 861, 862, 863, 864, 865, 866, 867, 868, 869, 870, 871, 872, 873, 874, 875, 876, 877, 878, 879, 880, 881, 882, 883, 884, 885, 886, 887, 888, 889, 890, 891, 892, 893, 894, 895, 896, 897, 898, 899, 900, 901, 902, 903, 904, 905, 906, 907, 908, 909, 910, 911, 912, 913, 914, 915, 916, 917, 918, 919, 920, 921, 922, 923, 924, 925, 926, 927, 928, 929, 930, 931, 932, 933, 934, 935, 936, 937, 938, 939, 940, 941, 942, 943, 944, 945, 946, 947, 948, 949, 950, 951, 952, 953, 954, 955, 956, 957, 958, 959, 960, 961, 962, 963, 964, 965, 966, 967, 968, 969, 970, 971, 972, 973, 974, 975, 976, 977, 978, 979, 980, 981, 982, 983, 984, 985, 986, 987, 988, 989, 990, 991, 992, 993, 994, 995, 996, 997, 998, 999, 1000.

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TABLE 3-27
SUMMARY OF BOILER PERFORMANCE CALCULATIONS

Boiler No.	Firing Mode	Test No.	Load, MW	% O ₂	PPM	NO _x Emissions, (3% O ₂) Lb/10 ⁶ Btu	ng/J	Coal Ash, % (Wet Basis)	% Carbon on Particulate	Boiler Efficiency, %	Avg. Eff.
2	Baseline	41	178	4.2	612	0.82	351	12.37	1.48	89.82	90
2	Baseline	43	155	5.4	574	0.77	329	12.76	0.94	90.12	
2	Low NO _x	59	123	5.0	381	0.51	218	11.30	1.81	90.44	
2	Low NO _x	60	123	6.6	490	0.65	281	10.41	1.87	90.36	90.4
7	Baseline	152	417	5.5	848	1.13	486	16.48	0.87	88.86	
7	Low NO _x	151	432	3.1	508	0.68	291	12.45	2.98	88.92	
7	Low NO _x	153	430	1.9	456	0.61	261	14.32	1.71	89.27	89.1

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3.6 Anti-Slagging Additive Tests

Since 1970, Exxon Research under EPA sponsorship has conducted NO_x control studies on more than 60 utility boilers over 35 of which were pulverized coal fired. As indicated elsewhere in this and prior reports (2) (3), the most effective NO_x combustion modification techniques have been staged firing in combination with low excess air operation. These techniques, however, result in reducing atmospheres in the bottom of the furnace and are often accompanied by higher temperatures. In pulverized coal fired boilers these effects could have a tendency toward increased slagging problems, especially where boilers may be operating at or near incipient slagging conditions. Under reducing atmospheres coal ash fusion temperatures generally are about 200°F lower than for oxidizing conditions. This fact, coupled with higher furnace temperatures, can affect the character of slag formations making them more fluid and sticky, with potentially greater slagging difficulties. During tests on the 35 coal-fired boilers mentioned, however, virtually no increased slagging occurred under "low NO_x" operation for periods of two weeks or longer of a magnitude that could not be handled by regular clean-up procedures or by normal slag and soot blowing cycle frequencies. In several instances, though, in short term tests, there were some indications that slagging might become a problem under more extensive "low NO_x" combustion operation, e.g. if excess air were reduced further.

Since combustion modifications for NO_x emission control directionally can produce conditions which may aggravate slagging problems in boiler furnaces, a part of the investigative program was devoted to means for alleviating increased slagging conditions which might limit the use of these techniques. A number of alternatives were considered, but it appeared that the simplest and least expensive might be the use of an anti-slagging additive. Additives, or "chemical additions" to the fuel combustion process, have been used successfully for years to control fireside slagging, corrosion and fouling in oil-fired utility boilers. In recent years, however, trials with additives in coal fired boilers for other purposes gave indications that certain chemicals might be effective in suppressing slag formation and be of assistance in keeping furnaces cleaner.

Contacts were made with interested additive suppliers, and the cooperation of the boiler manufacturers was solicited for assistance in arranging and developing a test program. Louisville Gas and Electric Company agreed to cooperate in the additive test experiments. The No. 1 and 2 Combustion Engineering boilers at LG&E's Mill Creek station had a history of slagging at rated load (325 MW) due to the type of coal fired. In order to maintain manageable slagging conditions, LG&E had arbitrarily derated output on these units to 300 MW except for short periods of exceptional demand. Thus, these boilers were prime candidates for the initial demonstration trials which were conducted on boiler No. 1 during September and October, 1978.

3.6.1 Initial Test Procedures

Tests commenced on Monday mornings with a "clean" boiler after a weekend of low load operation during which the boiler was deslagged. Observations of slagging conditions were made twice per day; in the morning before load pick-up to 300 MW and at night before normal load reduction for deslagging and cleanup. Control room board data were logged every two hours during this period as was soot and slag blowing frequency. Observations of slagging conditions were made, twice daily, through 48 inspection doors spaced throughout the furnace; once in the morning, when the furnace was cleanest, and again in the evening when slag accumulations were expected to be at their maximum.

A four-digit rating system was used to facilitate recording observations and to make comparisons. (The raw data will appear in a Data Supplement to the Phase II work. This Data Supplement will issue in the near future.)

Although the slag rating system provided positive indication of the degree of slagging, it failed to clearly pinpoint the criticality of the operation. A comparison of observed ratings between baseline and additive runs successfully showed differences in the degree of fouling but failed to indicate that slagging was critical and that boiler conditions had reached their limits of endurance in maintaining operability. It was concluded, therefore, that slag observation ratings were useful and expedient but that they could not supplant judgment by experienced operators weighing both visual observations and indications from boiler parameters (control room indicators and recorders) to make sound but subjective judgments.

During the preliminary tests, the boiler was operated at 300 MW load without additive injection in order to build-up data and experience characterizing baseline operating conditions and slagging characteristics. Every morning around 8 or 9 a.m. the boiler was brought up to 300 MW and held at this load for at least 12 hours until normal load drop off occurred in the evening. During the early hours of each morning, load was reduced to very low levels (100-150 MW) to de-slag the unit in preparation for the next test later in the day. This is normal practice at most coal-fired power plants.

During subsequent tests, two types of additives were injected under identical test conditions to the baseline tests. Slag observations and pertinent operating data were recorded as before. Basic Chemicals UltraMag additive used in the first tests, was injected continuously at a rate of $0.0016 \text{ m}^3/\text{sec}$ (15 GPH) (double the expected effective rate) through eight injectors installed in 4 corner inspection doors each at the B and C slag blower elevations located immediately above the top burners. UltraMag is a dispersion of ultra-fine (<2 micrometers) MgO in distillate (No. 2) oil. These tests were followed by trials with additive supplied by Betz Laboratories, Inc. consisting of a fine

(<300 mesh) dry powder of Al_2O_3 and TiO_2 . However, rather than continuous injection, this additive was batch fed every 2 to 4 hours by blowing a total of 30-50 lbs into the furnace through two inspection doors immediately above the burners.

3.6.2 Initial Test Results

Most of the initial tests run during September and October, 1978 were conducted at a load of 300 MW in order to keep from slagging the boiler too badly. Unfortunately, no beneficial effects of the additive could be observed at this load. At LG&E's suggestion, therefore, load was deliberately increased to 340 MW (overload) during the last few days of testing with UltraMag additive so that slagging conditions would be intensified and potential effects of the additive would be more discernable. After 12 hours operation at the 340 MW level, the boiler was reasonably well slagged but steam temperatures were still in control. Burner tilt was depressed, as expected, and superheat and reheat spraywater flows were high but not critical. Boiler parameters gave every indication that operation at this load could be continued for 3 to 5 hours without conditions becoming critical. It was concluded at this point that the additive had indeed shown a beneficial effect but to prove the point it was decided to run the following day at the same load without additive injection. Accordingly, injection of additive was discontinued and boiler load was reduced to low levels during the night for deslagging, in keeping with normal practice.

After about 12 hours operation of the boiler without additive at the 340 MW level the next day, it was clear that operating conditions were critical and that load would have to be reduced to keep superheat and reheat steam temperature under control and to prevent further slag build-up in the furnace which would further aggravate the incipient critical operating conditions. Burner tilt again was depressed, as expected, but superheater and reheater spray water flows were at their maximum, bordering on uncontrollability. Furthermore, attemperator water spray flow rates were at a higher level for the non-additive operation than they were for the previous day's operation with additive. Based on these indications and visual observations of slagging conditions, it was concluded that Basic Chemicals UltraMag additive had been quite beneficial in suppressing slag buildup in the No. 1 boiler. However, the UltraMag supply had been depleted at this point and further confirmation of the effects could not be assessed or quantified.

Results of the tests with the Betz Laboratories, Inc. $\text{Al}_2\text{O}_3/\text{TiO}_2$ additives batch fed to the furnace on an intermittent basis through inspection doors above the burners were not quite as conclusive. Thirty to fifty pounds of additive was blown onto the slag clinging to the walls adjacent to two inspection doors every 2-4 hours. Visual inspection after about 10 minutes showed a dramatic change in the

physical characteristics of the slag and there was little doubt that the Betz additive had a beneficial effect on this slag. However, the limited number of injection ports used, the incomplete coverage of wall surfaces and intermittent rather than continuous injection prevented its effect from being more pronounced. Again, insufficient time and the limited supply of additive available prevented further development of potential beneficial effects.

3.6.3 Supplemental Additive Tests - Procedures

As indicated above, most of the initial additive tests were conducted at approximately 300 MW. It was only in the last few days of testing, when load had been increased to 340 MW to intensify slagging conditions, that positive indications of the additives effectiveness were obtained. By this time, however, additive supplies were depleted and testing was concluded before further evaluation was possible. Due to the surprising indication that additives might really be successful in suppressing slagging tendencies in pulverized coal fired boilers at low injection rates, all parties concerned, by mutual agreement, decided to undertake further tests.

Accordingly, a second series of tests were run during June, 1979 using Basic Chemicals UltraMag product. The principal objective of these tests was to evaluate the effectiveness of the anti-slagging additive under intensified boiler operations. Boiler loads of 325-330 MW, sufficient to promote slagging, were carried but this time the tests were allowed to proceed until boiler operating parameters became near critical forcing a cut-back in load.

A total of eight tests were run; four without additive injection to obtain "baseline" operating information and four with additive at three different injection rates and methods. As in the previous tests, the additive was injected through eight inspection doors, four each at the corners of the B and C slag blower elevations immediately above the top burners. The first two additive runs were conducted while injecting the additive continuously at a rate of 15 gallons per hour (GPH). This is a very low rate for coal firing but was double the rate Basic Chemicals considered might be the optimum rate. In order for the additive to be economically attractive, it was postulated that a dosage based on surface effect on the ash particle rather than a mass effect would have to be achieved with the additive. During the third test additive was injected at the rate of 7.5 GPH, or at the projected economical, optimum rate. The last test was conducted while "slug" feeding the additive through the eight injectors every hour with a total of 15 gallons of additive mixture. Approximately 15 minutes was required to slug feed this amount of additive to the furnace through the eight injectors resulting in a relatively high injection rate for this short period.

3.6.4 Supplemental Additive Test Results

Results of the anti-slugging additive trials are summarized in Table 3-28. Referring to Table 3-28, it may be seen that tests Nos. 200, 201, and 203 (baseline - no additive) achieved 12 hours operation at full load, rated conditions (325-330 MW) before superheat and reheat steam temperatures bordered on uncontrollability. Attention is called, however, to test No. 202 (no additive) where the boiler was slugged-up to the point of being out of control in 4 1/2 hours; a very short period. The reasons for this drastic performance were not readily apparent but may possibly be attributed to the fact that the furnace clean-up prior to the test may not have been as effective as before or that a change to a higher slugging coal may have occurred for that day. The latter, however, does not seem probable as a normal 12 hours operation was obtained the next day under the same operating conditions. In any event, it did happen and could happen when additive was being injected to confuse judgment on the effectiveness of the additive.

During Tests Nos. 204 and 205 additive was injected continuously at the rate of 15 GPH. Referring to Table 3-28 it may be observed that full load capability of the boiler could be maintained under these conditions for a period of 15 and 17 hours, respectively, or an additional 3 and 5 hours longer than without additive injection. These results testify to the technical feasibility and effectiveness of the use of additives at low injection rates with pulverized coal firing. Under tight load demand circumstances, therefore, additive usage may provide an economically viable alternative to improve and enhance load carrying capability in utility boilers. These results give promise of potential solution or amelioration of slugging conditions wherever low NO_x combustion modifications may tend to promote increased slugging conditions.

Other potential benefits, which were beyond the scope of these investigations, may also accrue from additive usage, such as, easier clean-up of the boiler during nightly reduced load periods. For example, it may not be necessary to reduce load as much and the clean-up period possibly may be shortened to achieve the same degree of cleanliness. Load carrying capabilities, which are of special importance in tight load demand situations, therefore could be improved.

Test No. 206 was run in an attempt to optimize additive injection rate. It may be observed that load carrying capability during this test (12 hours duration) was the same as without additive in tests Nos. 200, 201 and 203. The conclusion could be made that additive injection at the rate of 7.5 GPH was ineffectual. However, before drawing firm conclusions, more tests and data are required as any real benefits from short term tests of this type may have been obscured by other test circumstances. The same comment can be made concerning the results of test No. 207 where additive was slug fed every hour to the furnace in 15 gallon batches. No advantage is apparent in Table 3-28 for slug feeding vs. continuous feeding at the same rate as in tests Nos. 204 and 205. Injection of additive on a continuous basis, however, appears to be preferable but further tests are needed in order to confirm these observations.

TABLE 3-28

SUMMARY OF ANTI-SLAGGING ADDITIVE TEST RESULTS

Test No.	Date	Time	Hours @ Full Load (325-330 MW)	O ₂ , %	NO _x PPM (3% O ₂)	Test Condition
200	6/11/79	07:27 Start 13:53 16:16 19:27 End	12	5.0 5.3	584 599	Baseline (No Additive)
201	6/13/79	10:00 Start 11:06 15:36 22:00 End	12	4.7 5.2	512 566	Baseline (No Additive)
202	6/14/79	10:00 Start 13:18 *14:30 End 16:15 Load Cut Back	4.5	5.0	557	Baseline (No Additive)
203	6/18/79	07:00 Start 08:16 13:45 15:58 19:00 End	12	4.8 4.8 4.9	448 479 517	Baseline (No Additive)
204	6/20/79	07:10 Start 09:26 13:35 16:00 22:20 End	15	4.5 4.6 4.6	447 473 572	Additive (15 GPH)
205	6/21/79	08:15 Start 09:38 13:00 15:35 01:15 End	17	5.3 5.3 5.7	514 534 581	Additive (15 GPH)
206	6/25/79	09:00 Start 21:00 End	12	—**	—	Additive (7.5 GPH)
207		09:30 Start 23:10 End	14	—	—	Additive (15 GPH Slugs)

*SH/RH sprays max. @ 14:30.

**Blanks indicate that these data are not available.

3.6.5 Affect of Furnace Cleanliness on NO_x Emissions

Another observation is pertinent at this point aside from the main objective of the additive tests. As shown in Table 3-28, gaseous emission data were recorded during tests Nos. 200 through 205. A fact not apparent from previously reported test data bears comment. NO_x emission data in most reports normally do not reflect the cleanliness of the boiler. Data reported in Table 3-28 show the effect of the cleanliness of the boiler on NO_x emissions with time for the same operating conditions. Note that NO_x emissions were lowest with a "clean" furnace early in the day and increased progressively with time as furnace surfaces became fouled with slag (furnace temperatures increase). Technically, these facts were recognized during earlier NO_x studies (EPA 600/7-77-117), but these data demonstrate this effect dramatically.

3.6.6 Conclusions

It is concluded from these limited tests that additive usage is technically feasible and may be effective in controlling or ameliorating slagging problems in pulverized coal fired utility boilers especially when "low NO_x" combustion modifications may be employed. The degree of slag reduction and the benefits of increased load carrying capability, however, need to be defined in more extensive test programs to shed more light on the economics and technical feasibility of additive usage for this purpose.

3.7 Analysis of SASS Train Stack Emissions

3.7.1 Summary

SASS train samples collected in May and June of 1977 from coal-fired power plants at the East Kentucky Power Cooperative, Inc and the Public Service Company of Colorado were analyzed for metals, polynuclear aromatic hydrocarbons (PNA's), and anions. The analytical data indicate that neither baseline nor low NO_x operation of the Colorado plant significantly reduced all metal emissions. Although PNA levels were consistently below the requested 2 µg/m³ detection limit, small amounts (0.1-0.8 µg/m³) were detected on particulate samples from Kentucky. The Colorado anion data show that lower amounts were present on the particulate samples under low NO_x conditions while higher levels were observed on the condensate sample.

SASS tests were also run at Gulf Power Company's Crist Station. These results will be included in a separate report describing the work at Crist.

A description of the sampling system along with details of the analytical techniques used in the screening for toxic materials is presented in this section of the report.

3.7.2 General

In May and June of 1977, stack gas samples were collected from the East Kentucky Rural Cooperative and the Public Service of Colorado coal-fired power plants. The sampling device used was the Source Assessment Sampling System (SASS).

The main purpose of the study was to determine if toxic materials are emitted from power plant boilers fired by different coals under both baseline and low NO_x conditions. This section presents the analytical results obtained from the analysis of the SASS train samples for metals, PNA's, organohalides, and various anions.

3.7.3 Sampling and Analysis

All samples were collected with a SASS train. This device was developed by EPA (IERL-RTP) and manufactured by Acurex Aerotherm Corp. The main objective was to have a single device which would sample stack emissions for particulate and organic materials simultaneously. A diagram detailing the various components of the system is illustrated in Figure 3-21.

The flue gases first pass through a heated stainless steel probe and then into an oven which is maintained at 400°F. In this oven there are three cyclones which are used to separate particles by size

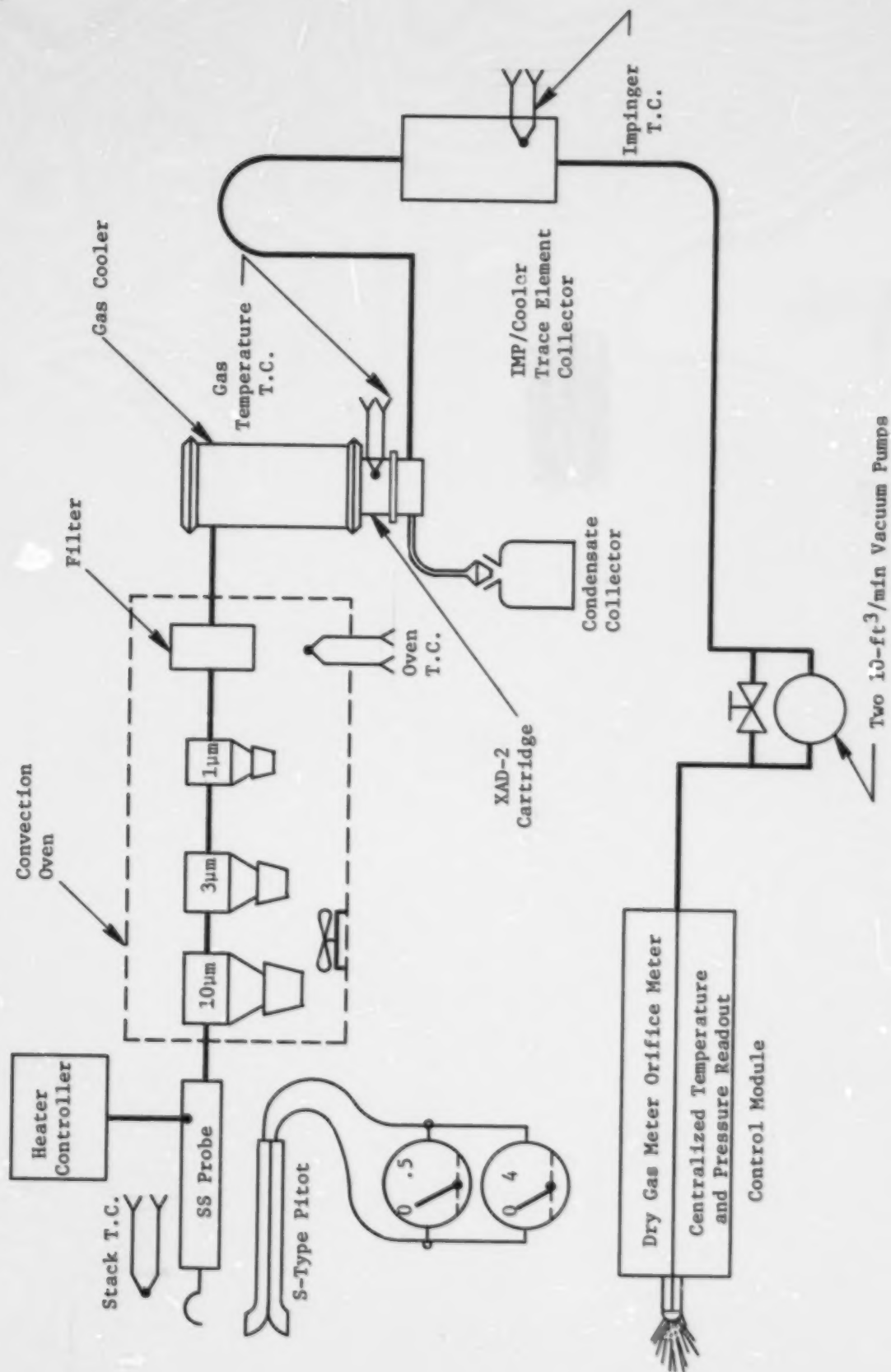


Figure 3-21. Source Assessment Sampling System Schematic.

(10 μm , 3 μm , 1 μm) prior to the entrapment of material less than 1 μm on a final filter. The hot gases are then cooled to approximately 70°F. The resulting condensate and remaining gases pass through an XAD-2 adsorbent cartridge. The purpose of the XAD-2 resin is to adsorb organic materials which are present either in the liquid or gaseous form. The organic materials of main interest are PNA's (polynuclear aromatic hydrocarbons). The condensate solution which has passed through the XAD-2 resin bed then drains into a trap. Depending on the amount of condensate collected over a typical run time (~5 hr.), the liquid is periodically removed from the trap.

The impinger solutions serve a three-fold purpose. The first impinger, which contains hydrogen peroxide, prevents reducing gases such as sulfur dioxide from reducing the collection efficiency of impingers 2 and 3. These impingers contain ammonium persulfate and silver nitrate solutions which will entrap volatile metals by oxidative dissolution. A fourth impinger which contains silica gel is used to prevent moisture from reaching the SASS train pumps.

The SASS train is normally operated at 4.0 standard ft³/min, and at this rate the required sample size of 30m³ (1,060 scf) takes almost 5 hours of continuous operation. A list of samples and air volumes is shown in Table 3-29 for the Kentucky and Colorado runs.

Different analyses were performed on the four SASS train samples. Table 3-30 lists the analyses performed on each sample with Table 3-31 summarizing the methods used. A more detailed description of the analytical procedures is described in Appendix D.

3.7.4 Results and Discussion

The main emphasis of the project was one of general survey to determine if toxic materials are emitted from coal-fired boilers. In order to satisfy this contract (No. 68-02-1415) the analyses listed in Table 3-30 were performed.

A. CHN Analysis

The carbon, hydrogen, and nitrogen analyses of the coal and cyclone samples are listed in Table 3-32 with Table 3-33 showing the percent of each cyclone used in preparing the composite sample for the CHN analysis. The data indicate that for the baseline conditions there appears to be a lower percent carbon emission. However, since the carbon levels in the coal vary from test locations, this correlation may not be accurate.

B. Metals

The amount of particulate and solids from the washings are listed in Table 3-34. The 10 μm cyclone and probe particulate were combined.

TABLE 3-29AIR VOLUMES SAMPLED IN SASS TRAIN RUNS

<u>Location</u>	<u>Volume, m³</u>
East Kentucky Rural Cooperative	
Baseline (Test 80) (May 4, 1977)	18.8
Low NO _x (Test 82) (May 10, 1977)	13.3
Public Service of Colorado	
Baseline (Test 16) (June 14, 1977)	30.6
Low NO _x (Test 14) (June 7, 1977)	22.8

TABLE 3-30

ANALYSIS OF SASS TRAIN SAMPLES

Source Type	Test No.	East Kentucky		P.S. of Colorado	
		Base 80	Low NO _x 82	Base 16	Low NO _x 14
A. <u>Particulate</u>					
Trace metals (by particle size)		X		X	X
PNA (by particle size)		X		X	
Organochlorides (by particle size)				X	
F ⁻ , NO ₃ ⁻ , SO ₄ ⁼				X	X
Carbon		X	X	X	X
B. <u>Condensate</u>					
Trace metals		X		X	X
Cl ⁻ , F ⁻ , CN ⁻ , NO ⁻ , SO ⁼		X		X	X
C. <u>Amberlite XAD-2 Adsorbent</u>					
Trace metals		X		X	X
PNA		X	X		
Organochlorides			X		
D. <u>Impinger Solution 1</u>					
Volatile trace metals		X		X	X
E. <u>Impinger Solution 2</u>					
Volatile trace metals		X		X	X
F. <u>Coal</u>					
Trace metals		X		X	X
Carbon		X	X	X	X

TABLE 3-31
ANALYTICAL METHODS FOR STACK GAS EMISSION SAMPLES

<u>Test Requested</u>	<u>Sample Tested</u>	<u>Method Used</u>	<u>Comment</u>
Metals	Particulate Condensate XAD-2 Resin Impinger Soln 1 Impinger Soln 2 & 3 Coal	INAA (AAS for Ni, Be, Cd, Pb)	INAA Analyses Performed by Virginia Polytechnic Institute
PNA's	Particulate XAD-2 Resin	GC/UV	
Chloride	Condensate	Titration with Silver Nitrate	
Fluoride	Particulate Condensate	Liquids - Specification electrode Solids - Sodium carbonate fusion D-ION-X ion chromatography	
Cyanide	Condensate	ASTM No. 2036	
Nitrate	Particulate Condensate	Colorimetric method UV Absorbance	
Sulfate	Particulate Condensate	Barium Perchlorate Titration	
Organochlorides	Particulate XAD-2 Resin	Microcoulometry	
			Water Soluble Nitrate
			Water Soluble Nitrate

TABLE 3-32

CHN ANALYSIS OF COAL AND CYCLONE BLENDS

	<u>Test No.</u>	<u>Sample</u>	<u>Firing Cond.</u>	<u>% Carbon</u>	<u>% Hydrogen</u>	<u>% Nitrogen</u>
P.S. of Colorado	14	Coal	Low NO _x	43.13	3.33	0.64
	14	Cyclones	Low NO _x	1.07	<0.2	<0.2
	16	Coal	Base	57.99	4.84	0.91
	16	Cyclones	Base	0.81	<0.2	<0.2
East Kentucky	80	Coal	Base	64.23	4.72	1.35
	80	Cyclones	Base	2.85	<0.2	<0.2
	82	Coal	Low NO _x	71.84	4.58	1.79
	82	Cyclones	Low NO _x	5.75	<0.2	<0.2

TABLE 3-33

PERCENT OF PARTICULATE SIZE FRACTIONS
USED IN CHN ANALYSIS OF CYCLONE SAMPLES

<u>Test No.</u>	<u>10 µm Cyclone</u>	<u>3 µm Cyclone</u>	<u>1 µm Cyclone</u>
14	74.5	14.2	11.3
16	70.7	20.3	9.0
80	76.8	20.5	2.7
82	77.6	19.7	2.7

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TABLE 3-34

MASS OF MATERIAL COLLECTED IN CYCLONES
(Reported in grams)

Sample	P.S. of Colorado		East Kentucky	
	Test No.		Test No.	
	14	16	80	82
	Low NO _x	Base	Base	Low NO _x
10 μm Cyclone & Probe	37.32	66.34	334.85	288.46
10 μm Wash	1.12	0.32	0.75	--a
10 μm Probe Total	38.44	66.66	335.60	288.46
3 μm Cyclone	7.22	19.04	89.10	73.33
3 μm Wash	0.12	0.06	0.34	--a
3 μm Total	7.34	19.10	89.44	73.33
1 μm Cyclone & Final	5.63	8.41	11.74	10.17
1 μm Wash	0.22	0.10	0.25	--a
1 μm Final Filter Total	5.85	8.51	11.99	10.17
Total Particulate Mass Collected	51.63	94.27	437.03	371.96

a Washes were not evaporated for total solids.

b5356

TABLE 3-35
SOLUTION VOLUME (ml) AND XAD-2 MASS (g) FOR SASS TRAIN RUNS

Sample	P.S. of Colorado		East Kentucky	
	Test No.		Test No.	
	14	16	80	82
	Low NO _x	Base	Base	Low NO _x
Condensate	964	825	729	
Impinger #1	1316	1746	1363	
Impinger #2 & 3	1576	2324	2366	
XAD-2	121.5	130.2	150.6	151.0

Similarly, the 1 μ m cyclone and final filter material were combined. The solution volumes and amount of XAD-2 used for each test are summarized in Table 3-35. The data presented in these two tables are used in the calculations of the amounts of metals, PNA's, and anions per cubic meter of air emitted from the power plants.

Each section of the SASS train was analyzed for trace metals. A summary of the metal data is presented in Table 3-36. These results were obtained by summing the metal data for all sections of the SASS train. Of the 13 EPA priority pollutant metals (listed at top of Table 3-36) Cr, Cu, Ni, Se, Ti and Zn were found in highest concentrations. The levels of As, Be, Cd, Hg and Sb were lower in concentration. Data are also reported on 29 other elements with Al, Ba, Fe, Mg, Na and Sr present in some tests at levels greater than 20,000 μ g/m³. Higher metal concentrations are also noted for the coal fired at the East Kentucky Power Cooperative plant than for the Western coal fired at the Public Service Company of Colorado plant.

The metal data for SASS train tests No. 14, 16, 80, and NBS standard reference materials are summarized in Tables 3-37, 3-38, 3-39, 3-40, respectively. Neutron activation analysis was the technique used for all elements except Be, Cd, Ni, and Pb, which are important elements from a toxicity viewpoint and are best analyzed by atomic absorption. For comparative purposes, duplicate samples were sent to Virginia Polytechnic Institute for INAA analysis. In cases where this was done, both results are shown in the Tables. In many instances the agreement was within acceptable limits of the EPA sampling and analysis protocol. However, elements which show large differences between replicate samples or a value for one sample and not reported (NR) for the other may indicate that there were problems caused by contamination, interelement interference, nearness to detection limits, or inconsistent interpretation.

Since blank solutions were not available in proportions of impinger and wash solutions used, it was difficult to correct the sample for a blank. Therefore, the impinger results were reported in ppm amounts. An element of possible interest would be mercury. One will notice, however, that the impinger blank contains about the same level as the sample.

From the metal data of tests 14 (low NO_x) and 16 (baseline) it does not appear that either set of plant operating conditions is better in reducing all metallic emissions. When comparisons are made, the concentration of metallic emissions vary from baseline to low NO_x conditions depending on the element and the SASS train sample in question. Often, however, these differences are not significant.

C. Polynuclear Aromatics

The particulate and XAD-2 samples were analyzed for PNA's following the procedure outlined in Appendix B. The percent extractables is shown in Table 3-41. The percent carbon-14 recovery of benzo(a)anthracene and benzo(a)pyrene after soxhlet extraction is listed in Table 3-42. Low recoveries were observed for the 10 μ m cyclone catches for both tests. This phenomenon was previously observed in samples of carbon black where PNA's could not be extracted (4), (5). Because of these low PNA recoveries the two 10 μ m samples were not analyzed.

TABLE 3-36
SUMMARY OF METAL DATA ON STACK EMISSIONS
 ($\mu\text{g}/\text{m}^3$)

	P.S. of Colorado				East Kentucky	
	Test No. 14		Test No. 16		Test No. 80	
	Low NO _x		Base		Base	
Ag	NR,	NR	NR,	NR	NR,	NR
As	118,	128	132,	151	2775,	2875
Be	9.4,	-	14.5,	-	275,	-
Cd	27,	-	19,	-	180,	-
Cr	969,	962	747,	721	3873,	3573
Cu	1187,	-	218,	218	4082,	2067
Hg	18,	18	19,	17	39,	39
Ni	1099,	-	316,	-	5680,	-
Pb	176,	-	235,	-	2213,	-
Sb	92,	94	71,	73	334,	331
Se	578,	560	207,	184	364,	698
Ti	40984,	36631	1511,	11508	177214,	148730
Zn	7884,	7879	7118,	7307	13845,	13707
Al	460000,	200000	252000,	257000	2672000,	2800000
Au	1.5,	1.5	0.8,	1.0	1.6,	2.0
Ba	18613,	14200	22300,	25095	31907,	88607
Br	1064,	1047	853,	808	1017,	1288
Ce	540,	516	638,	555	5397,	4581
Co	188,	195	237,	238	1110,	1035
Cs	74,	76	44,	40	207,	135
Eu	4.3,	6.3	11.2,	11.2	70.8,	63.6
Dy	105,	92	122,	127	836,	790
Fe	166000,	16400	100490,	89180	1747000,	136000
Hf	63,	68	28,	18	164,	150
I	2633,	2715	2.7,	2.7	1031,	1494
K	8827,	13592	13860,	15708	546700,	546600
La	107,	159	241,	245	2096,	2166
Lu	0.7,	0.9	2.0,	2.0	19,	15
Mg	231000,	234000	139000,	103000	462501,	391000
Mn	1275,	1618	1139,	479	3688,	2568
Mo	159,	170	113,	120	543,	493
Na	20281,	27711	37700,	38800	40670,	42140
Rb	190,	79	178,	276	3423,	2593
Sc	7.8,	25	55,	50	367,	344
Sm	105,	149	212,	216	1835,	1815
Sn	18190,	19180	6990,	7276	1134,	14.5
Sr	10220,	2190	20120,	30220	168167,	184241
Th	165,	171	365,	340	1150,	998
U	14.3,	19.5	30,	34	234,	334
V	24.3,	23.8	37.2,	37.7	205,	199
Yb	420,	422	24,	23	114,	128

TABLE 3-37
METAL DATA FOR TEST NUMBER 14 (Low NO_x)
P.S. CO. OF COLORADO

Element	Coal (ppm)	10 μ m Cyclone (μ g/m ³)	3 μ m Cyclone (μ g/m ³)	1 μ m Cyclone (μ g/m ³)	Condensate (μ g/m ³)
Al	4600,	120000,	310000,	26000,	220,
As	2.2,	32	11,	28,	34,
Au	0.02,	0.03,	0.01,	0.02,	0.01,
Ba	520,	13000,	2000,	3600,	13,
Be	<0.5	6.6	1.5	1.1	<0.21
Br	3.1,	25,	6.4,	4.4,	34,
Cd	<1	20	1.9	1.3	<1.1
Ce	8.1,	220,	48,	44,	NR,
Co	2.6,	30,	7.4,	7.2,	8.5,
Cr	5.0,	150,	35,	31,	180,
Cs	0.3,	7.9,	0.8,	0.8,	NR,
Cu	NR,	NR,	NR,	NR,	42,
Eu	0.1,	1.7,	0.6,	0.5,	NR,
Dy	1.4,	42,	8.4,	6.2,	NR,
Fe	1900,	41000,	10000,	8000,	1200,
Hf	0.4,	9.6,	1.7,	1.2,	NR,
Hg	NR,	NR,	NR,	NR,	0.30
I	NR,	NR,	NR,	NR,	0.42
K	270,	5900,	1500,	1200,	85,
La	3.6,	63,	14,	16,	150
Lu	NR,	0.51,	0.1,	0.1,	0.13,
Mg	2200,	39000,	13000,	11000,	NR,
Mn	9.1,	170,	97,	62,	200,
Mo	1.0,	16,	5.2,	6.2,	5
		29	6.8	5.8	10

TABLE 3-37 (CONT'D)

Element	Coal (ppm)	10 μ m Cyclone (μ g/m ³)	3 μ m Cyclone (μ g/m ³)	1 μ m Cyclone (μ g/m ³)	Condensate (μ g/m ³)
Ni	<5	190	27	23	850
Pb	<5	110	29	36	0.85
Rb	NR	96, NR	20, 21	16, NR	NR, NR
Sb	0.2, 0.2	2.7, 4.2	0.9, 1.4	2.3, 1.8	0.85, 1.3
Sc	0.7, 0.7	NR, 17	4.2, 4.5	3.6, 3.1	NR, NR
Se	NR, 0.8	15, NR	4.8, 5.5	11, 11	17, 13
Sm	3.0, 3.1	47, 85	9.7, 16.7	13, 12	0.25, 0.17
Sn	110, 41	NR, 1300	770, NR	NR, 460	3.0, NR
Sr	340, NR	6300, NR	3900, 1200	NR, 930	17, 59
Th	2.7, 1.3	52, 56	13, 16	11, 9.8	NR, NR
Ti	490, 360	8100, 11000	3100, 2300	2100, 1500	13, 160
U	0.5, 0.5	5.6, 11	2.3, 2.6	2.6, 2.4	0.30, NR
V	13, 16	290, 320	87, 71	100, 86	2.1, 13
W	0.6, 0.8	5.1, 3.5	1.0, 1.9	2.2, 2.0	1.3, 1.7
Yb	0.2, 0.2	3.2, 4.7	0.7, 1.2	0.8, 0.7	NR, NR
Zn	14, 20	190, 100	39, 35	67, 75	89, 170

NR - means that the level of interfering compounds was covering the metal of interest. Therefore, a reportable result was not possible.

When two results are reported this indicates duplicate analysis.

TABLE 3-37 (CONT'D)

Element	XAD-2 ($\mu\text{g}/\text{m}^3$)	XAD-2 Blank ($\mu\text{g}/\text{m}^3$)	Impinger 1 (ppm)	Impinger 2 & 3 (ppm)	H ₂ O-IPA Blank (ppm)	(NH ₄) ₂ S ₂ O ₈ -AgNO ₃ Blank (ppm)
Al	8.5	2.7	4.9, 2.2	150, 34	13	3.2
As	0.011	0.027	0.1, 0.1	NR, 0.1	0.004	0.003
Au	0.005	0.0019	0.0004, 0.0002	0.02, 0.02	0.0003	NR
Ba	NR	NR	NR, NR	NR, NR	35	NR
Be	<0.016	<0.027				
Br	0.16	0.53	0.06, 0.3	16, 11	0.07	0.08
Cd	0.13	0.30	<0.025	<0.025	<0.025	<0.025
Ce	NR	0.53	NR, NR	3.3, NR	NR	NR
Co	0.53	0.53	0.1, 0.5	NR, 1.7	0.06	NR
Cr	0.17	1.1	1.9, 1.9	6.7, NR	NR	NR
Cs	0.037	0.05	NR, 0.05	0.9, NR	NR	NR
Cu	9.6	2.1	0.5, 0.6	16, NR	11	NR
Eu	NR	0.0016	0.003, 0.001	NR, 0.02	0.00009	0.3
Dy	0.037	NR	NR, NR	0.7, NR	NR	NR
Fe	45	36	34, 33	1500, NR	23	0.1
Hf	NR	NR	0.04, NR	0.7, NR	NR	NR
Hg	0.0016	0.016	0.01, 0.005	0.1, 0.4	0.008	0.5
I	NR	NR	45, 1.2	NR, NR	2.0	0.3
K	9.1	5.9	2.8, 1.9	NR, NR	0.5	NR
La	0.011	NR	0.007, 0.0007	0.2, 0.2	0.002	3.0
Lu	NR	0.0016	NR, NR	NR, NR	0.001	NR
Mg	NR	NR	NR, 160	NR, 2300	190	NR
Mn	0.75	NR	7.7, NR	6.4, NR	NR	NR
Mo	0.11	1.9	0.3, 0.3	1.0, 0.3	0.01	NR
Na	34	33	8.4, 10	77, 35	4.5	7.5

TABLE 3-37 (CONT'D)

Element	XAD-2 ($\mu\text{g}/\text{m}^3$)	XAD-2 Blank ($\mu\text{g}/\text{m}^3$)	Impinger 1 (ppm)	Impinger 2 & 3 (ppm)	H ₂ O-IPA Blank (ppm)	(NH ₄) ₂ S ₂ O ₈ -AgNO ₃ Blank (ppm)
Ni	9.6	1.0	1.0, NR	NR, NR	1.2	NR
Pb	1.5	42	0.03, 0.06	1.4, 0.9	0.02	0.02
Rb	NR	NR	NR, NR	NR, NR	NR	NR
Sb	0.016	0.027	NR, NR	7.6, NR	NR	NR
Sc	0.0011	NR	0.09, NR	0.2, 0.08	0.001	0.002
Se	0.05	0.13	0.002, 0.003	150, 310	NR	NR
Sm	0.0016	0.0021	26, NR	NR, NR	NR	NR
Sn	20	NR	NR, 0.1	0.7, 1.6	NR	0.2
Sr	NR	140	NR, 9.1	250, NR	42	NR
Th	0.016	0.11	NR, NR	0.1, 0.09	0.005	NR
Ti	NR	NR	NR, NR	NR, NR	NR	NR
U	0.0091	NR	2.6, NR	0.2, 0.2	0.006	NR
V	0.16	NR	0.02, 0.01	0.6, NR	0.01	NR
W	0.011	0.27	NR, 0.06	150, 63	1.8	6.3
Yb	NR	0.02	0.8, 2.1			
Zn	21	5.1				

NR - means that the level of interfering compounds was covering the metal of interest. Therefore, a reportable result is not possible.

TABLE 3-38
METAL DATA FOR TEST NUMBER 16 (BASELINE)
P.S. CO. OF COLORADO

Element	Coal (ppm)	10 μ m Cyclone (μ g/m ³)	3 μ m Cyclone (μ g/m ³)	1 μ m Cyclone (μ g/m ³)	Condensate (μ g/m ³)
Al	4000,	170000,	59000,	21000,	51,
As	1.3,	44,	24,	21,	35
Au	2.2	54	27	27	2.2,
Ba	0.06	NR,	0.03,	0.014,	NR
Be	260,	7800	3500	2800,	0.0054,
Br	<0.5	9.6	3.1	3900	2.7,
Cd	4.0,	70,	14,	1.7	<0.13
Ce	<1	8.7	3.7	5.6,	24,
Co	10,	440,	130,	2.2	<0.67
Cr	9.1	390	120	64,	0.81,
Cs	2.0	52,	19,	9.2,	NR
Cu	7.1	200,	62,	7.2	1.6,
Eu	0.6	5.7,	69	36,	13,
Hf	NR,	NR,	NR,	0.47,	13
I	NR,	NR,	NR,	1.0	NR,
K	0.1,	6.1,	NR,	NR	0.54
La	0.2	7.0	NR,	NR	1.1,
Lu	1.6,	54,	2.5,	1.0,	1.1
Mg	1.7	59	1.9	0.7	0.011,
Mn	1600,	2100	22,	8.3,	0.011
Mo	0.4,	70000,	21000	9.2	NR
Na	NR,	19,	4.0,	9200,	NR
	NR,	12	2.1	6400	750
	NR,	3.5,	NR,	1.3,	NR
	NR,	NR,	1.2	0.78	0.19,
	150,	NR,	NR	0.11	NR,
	2.9,	8900,	NR,	NR	0.081
	4.4	170,	2700	NR	1.6,
	NR	1.5,	43,	NR	1.6
	NR	1.3	45	22	24,
	0.02,	63000,	0.37,	20,	0.054,
	2500	35000	0.50	0.083,	0.081
	1500,	NR	26000,	0.14	NR,
	19,	740,	17000	11000	0.027
	NR	37,	140,	120	24,
	600	37,	16	120	5.4,
		24000,	12,	8.1	8.1,
		24000	8100	3600	170,

TABLE 3-38 (CONT'D)

Element	Coal (ppm)	10 μ m Cyclone (μ g/m ³)	3 μ m Cyclone (μ g/m ³)	1 μ m Cyclone (μ g/m ³)	Condensate (μ g/m ³)
Ni	<5	180	69	33	32
Pb	<5	140	47	47	0.54
Rb	7.0, NR	170, 220	NR, 56	7.8, NR	NR, NR
Sb	0.3, 0.3	6.5, 8.1	2.8, 2.9	2.0, 2.6	0.81, 0.54
Sc	0.8, 0.9	35, 31	11, 11	4.7, 3.3	NR, NR
Se	1.3, 2.0	22, NR	9.4, 11	19, 16	1.6, 1.6
Sm	3.0, 4.1	150, 150	39, 42	18, 19	0.054, 0.027
Sn	110, NR	NR, NR	190, 570	97, NR	NR, 2.7
Sr	430, 250	12000, 28000	6900, NR	1200, 2200	NR, NR
Th	2.3, 3.2	120, 100	31, 33	14, 8.1	0.81, 0.54
Ti	340, 230	15000, 16000	4700, 4900	1800, 1600	5.4, 2.7
U	0.2, 0.6	14, 18	4.9, 5.2	3.1, 3.1	0.054, NR
V	14, 15	460, 440	190, 180	120, 130	0.27, 0.27
W	NR, 0.4	8.3, 8.3	4.0, 4.3	1.8, 2.1	0.27, 0.24
Yb	0.2, 0.4	13, 10	1.9, 3.8	1.0, 1.2	0.27, 0.19
Zn	30, 56	480, 680	150, NR	81, 120	19, 19

NR - means that the level of interfering compounds was covering the metal of interest. Therefore, a reportable result was not possible.

TABLE 3-38 (CONT'D)

Element	XAD-2 ($\mu\text{g}/\text{m}^3$)	Impinger 1 (ppm)	Impinger 2 & 3 (ppm)	H ₂ O-IPA Blank (ppm)	(NH ₄) ₂ S ₂ O ₈ -AgNO ₃ Blank (ppm)
Al	8.5	1.0, 1.0	26, 18	13	3.2
As	0.13	0.04, 0.06	0.3, 0.7	0.004	0.003
Au	0.00085	0.00009, 0.001	0.1, 0.008	0.0003	NR
Ba	17	0.08, NR	130, NR	35	NR
Be	<0.013				
Br	0.26	0.03, 0.3	7.9, 11	0.07	0.08
Cd	0.081	<0.025	<0.025	<0.025	<0.025
Ce	0.26	NR, 0.05	NR, NR	NR	NR
Co	0.26	0.05, 0.05	2.3, 1.8	0.06	NR
Cr	4.3	0.03, 0.2	5.5, NR	NR	NR
Cs	NR	NR, NR	0.5, 0.5	NR	NR
Cu	1.3	0.5, 0.4	2.0, 2.9	11	NR
Eu	0.00038	0.001, 0.002	0.02, 0.02	0.00009	0.3
Dy	NR	NR, NR	0.5, NR	NR	NR
Fe	30	NR, NR	NR, NR	23	0.1
Hf	NR	NR, NR	0.6, NR	NR	NR
Hg	0.0051	0.006, 0.005	NR, 0.2	0.008	0.5
I	NR	0.01, 0.03	NR, NR	2.0	0.03
K	2.2	NR, 0.9	NR, 34	0.5	NR
La	0.013	0.003, 0.004	0.1, 0.09	0.002	3.0
Lu	0.0038	0.0004, 0.0005	NR, NR	0.001	NR
Mg	NR	NR, 0.9	530, NR	190	NR
Mn	0.77	0.1, 0.1	1.8, NR	NR	NR
Mo	1.4	0.2, 0.2	0.5, 0.5	0.01	NR
Na	14	6.5, 5.5	34, 34	4.5	7.5

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TABLE 3-38 (CONT'D)

Element	XAD-2 ($\mu\text{g}/\text{m}^3$)	Impinger 1 (ppm)	Impinger 2 & 3 (ppm)	H ₂ O-IPA Blank (ppm)	(NH ₄) ₂ S ₂ O ₈ -AgNO ₃ Blank (ppm)
Ni	1.6				
Pb	0.31				
Rb	NR	NR, NR	NR, NR	1.2	NR
Sb	0.026	0.02, 0.03	0.7, 0.8	0.02	0.02
Sc	0.0038	NR, NR	0.04, 0.08	NR	NR
Se	0.064	0.05, 0.07	NR, 2.0	NR	NR
Sm	0.0077	0.002, 0.001	0.04, 0.08	0.001	0.002
Sn	8.5	NR, 0.2	NR, 88	NR	NR
Sr	NR	0.3, NR	NR, NR	NR	NR
Th	0.026	0.02, 0.02	1.0, 4.2	NR	0.2
Ti	NR	0.1, 0.1	NR, NR	42	NR
U	0.0051	NR, 0.004	0.1, NR	0.005	NR
V	0.13	0.008, 0.006	0.3, 1.3	NR	NR
W	0.051	0.01, 0.01	0.3, 0.3	0.006	NR
Yb	NR	0.005, 0.003	0.1, NR	0.01	NR
Zn	4.3	1.5, 1.3	98, 68	1.8	6.3

NR - means that the level of interfering compounds was covering the metal of interest. Therefore, a reportable result was not possible.

TABLE 3-39

METAL DATA FOR TEST NUMBER 80 (BASELINE)
EAST KENTUCKY POWER COOPERATIVE

Element	Coal (ppm)	10 μ m Cyclone (μ g/m ³)	3 μ m Cyclone (μ g/m ³)	1 μ m Cyclone (μ g/m ³)	Condensate (μ g/m ³)
Al	15000, 18000	2000000, 2100000	570000, 620000	96000, 77000	23, 27
As	66, 120	1100, 1200	1100, 1100	540, 540	NR, NR
Au	0.004, 0.006	0.18, 0.36	0.095, 0.14	0.13, 0.19	0.31, 0.12
Ba	680, NR	23000, 86000	6200, 1200	2700, 1400	NR, NR
Be	1.9	180	81	14	<0.019
Br	15, 17	110, 300	21, 71	14, 5.4	540, 580
Cd	<1	130	33	11	<0.97
Ce	31, 34	3900, 3200	1300, 1200	190, 170	NR, 3.9
Co	6.6, 5.5	550, 450	180, 200	45, 50	12, 12
Cr	16, 13	2100, 1800	860, 810	190, 240	NR, NR
Ca	0.6, 1.5	160, 91	40, 38	7.0, 6.2	NR, NR
Cu	NR, NR	2500, 590	NR, NR	260, 150	7.8, 12
Eu	0.3, 0.5	50, 45	13, 11	2.3, 2.2	0.27, 0.12
Dy	5.4, 5.6	550, 540	200, 180	29, 23	NR, NR
Fe	21000, 20000	1400000, 1000000	180000, 170000	26000, 25000	1100, 930
Hf	0.9, 0.9	130, 120	30, 26	3.7, 3.9	NR, NR
Hg	0.2, 0.8	NR, NR	NR, NR	NR, NR	0.78, 0.35
I	19, NR	NR, 1400	NR, NR	NR, 55	85, 93
K	2200, 3700	410000, 410000	100000, 100000	20000, 20000	210, 130
La	8.8, 17	1600, 1700	400, 370	70, 70	0.39, 0.35
Lu	0.07, 0.1	13, 11	3.8, 2.4	0.57, 0.45	NR, 0.031
Mg	8300, 6200	410000, 230000	NR, 110000	22000, 20000	NR, 500
Mn	23, 12	2700, 1400	570, 770	160, 130	230, 240
Mo	1.7, 2.6	290, 250	110, 91	45, 54	3.9, 3.9
Na	170, 250	25000, 27000	7600, 7100	1600, 1500	190, 260

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TABLE 3-39 (CONT'D)

Element	Coal (ppm)	10 μ m Cyclone (μ g/m ³)	3 μ m Cyclone (μ g/m ³)	1 μ m Cyclone (μ g/m ³)	Condensate (μ g/m ³)
Ni	16	2000	710	190	2700
Pb	9	1400	670	140	1.9
Rb	12,	2600,	670,	130,	23,
Sb	1.9,	82,	40,	19,	NR
Sc	2.5,	270,	86,	11,	1.2,
Se	6.1,	NR,	NR,	4.0,	NR,
Sm	7.4,	1400,	360,	64,	3.1,
Sn	600,	NR,	NR,	1100,	0.078,
Sr	960,	75000,	39000,	NR,	19,
Th	5.8,	840,	290,	NR,	NR,
Ti	1200,	120000,	40000,	5200,	74
U	1.2,	170,	48,	15,	0.78
V	34,	3600,	1400,	310,	19,
W	0.9,	84,	38,	17,	35
Yb	0.8,	84,	24,	4.9,	0.39,
Zn	28,	2700,	810,	240,	0.35,
	40	2500	860	210	0.78
					0.27
					58,
					100

NR - means that the level of interfering compounds was covering the metal of interest. Therefore, a reportable result was not possible.

TABLE 3-39 (CONT'D)

Element	XAD-2 ($\mu\text{g}/\text{m}^3$)	Impinger 1 (ppm)	Impinger 2 & 3 (ppm)	H ₂ O-IPA Blank (ppm)	(NH ₄) ₂ S ₂ O ₈ -AgNO ₃ Blank (ppm)
Al	51	1.1, 1.8	18, 58	1.6	12
As	8.0	0.02, 0.02	NR, 0.2	0.009	0.02
Au	0.004	0.0002, 0.0002	NR, 0.009	0.0005	0.0003
Ba	NR	0.1, 0.08	NR, NR	0.6	NR
Be	0.024	0.3, 0.5	1.7, 3.1	0.1	0.08
Br	0.80	<0.025	<0.025	<0.025	<0.025
Cd	0.40	0.1, 0.1	NR, NR	NR	0.2
Ce	NR	0.07, 0.09	2.1, 2.9	0.08	0.1
Co	1.9	1.4, 1.3	5.4, 3.9	NR	0.5
Cr	34	NR, NR	NR, NR	NR	NR
Cs	0.080	NR, 0.3	8.5, 12	1.2	0.3
Cu	2.7	0.003, 0.0004	0.04, NR	0.0002	NR
Eu	0.0016	0.0006, NR	0.5, 0.4	0.002	0.2
Dy	NR	15, 12	NR, 1100	NR	46
Fe	380	NR, NR	NR, NR	NR	NR
Hf	0.040	0.006, 0.003	0.2, 0.4	0.008	0.02
Hg	0.0064	0.009, 0.01	7.5, NR	0.07	NR
I	1.3	1.9, 0.8	NR, 130	2.4	3.7
K	13	0.005, 0.005	NR, 0.2	NR	0.006
La	0.13	0.0008, 0.0008	0.01, NR	NR	0.003
Lu	0.0040	NR, 4.1	240, NR	NR	42
Mg	NR	0.2, 0.3	NR, NR	0.02	NR
Mn	10	0.1, 0.1	0.3, 0.8	0.04	NR
Mo	11	8.0, 8.1	41, 49	5.1	5.1
Na	33				

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TABLE 3-39 (CONT'D)

Element	XAD-2 ($\mu\text{g}/\text{m}^3$)	Impinger 1 (ppm)	Impinger 2 & 3 (ppm)	H ₂ O-IPA Blank (ppm)	(NH ₄) ₂ S ₂ O ₈ -AgNO ₃ Blank (ppm)
Ni	80				
Pb	1.3				
Rb	NR	NR, NR	NR, NR	NR	NR
Sb	0.24	0.03, 0.04	0.9, 2.1	0.03	0.04
Sc	0.024	NR, NR	NR, NR	NR	0.006
Se	0.64	0.06, NR	3.0, 2.6	NR	0.1
Sm	0.10	0.003, 0.003	0.08, NR	0.004	0.0009
Sn	NR	0.1, 0.3	NR, NR	NR	12
Sr	NR	0.7, 0.7	NR, 430	NR	NR
Th	0.13	NR, 0.02	NR, NR	0.03	0.05
Ti	14	0.4, 0.3	39, 150	2.3	9.8
U	0.080	NR, NR	NR, NR	0.007	NR
V	0.40	0.006, 0.009	0.5, 0.9	NR	NR
W	0.80	0.009, 0.007	0.5, 0.5	0.008	1.1
Yb	NR	0.008, 0.005	NR, NR	0.01	NR
Zn	25	3.3, 2.1	82, 73	NR	4.7

NR - means that the level of interfering compounds was covering the metal of interest.
Therefore, a reportable result was not possible.

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TABLE 3-40

METAL DATA FOR NBS STANDARDS

(Results reported in PPM)

Element	NBS Standard 1632 Trace Elements in Coal	1632 Certified Values	NBS Standard 1633 Trace Elements in Fly Ash	1633 Certified Values
Al	15000, 15000		100000, 99000	
As	10, 8.4	5.9	84, 79	61±6
Au	0.002, NR		0.2, 0.04	
Ba	560, NR		2300, 6300	
Be	1.6, 1.6	(1.5)	12, 13	(12)
Br	20, 18		29, 16	
Cd	<0.5	0.19	<2	1.45±0.06
Ce	23, 25		170, 210	
Co	5.3, 5.9	(6)	36, 37	(38)
Cr	17, 19	20.2	99, 120	131±2
Cs	1.6, 1.6		7.5, 6.2	
Cu	0.3, NR	18	NR, NR	128±5
Eu	NR, 0.2		2.4, 2.0	
Dy	3.0, 3.7		39, 20	
Fe	7400, 8100	8700	52000, 62000	
Hf	0.7, 1.1		6.5, 5.9	
Hg	NR, NR	0.12	NR, 1.1	0.14±0.01
I	NR, NR		NR, 44	
K	3400, 3000		20000, 19000	(17200)
La	8.9, 7.8		68, 63	
Lu	0.09, 0.04		0.6, 0.4	
Mg	6300, 1800		16000, 17000	
Mn	34, 37		530, 570	
Mo	3.0, 2.5	40	28, 18	493±7
Na	360, 320		2900, 2800	

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TABLE 3-40 (CONT'D)

Element	NBS Standard 1632 Trace Elements in Coal	1632 Certified Values	NBS Standard 1633 Trace Elements in Fly Ash	1633 Certified Values
Ni	15, 13	15	90, 98	98+3
Pb	36, 34	30	70, 72	70+4
Rb	29, 18		130, 170	(112)
Sb	3.5, 1.8		8.0, 6.6	
Sc	2.2, 2.4	2.9	15, 17	
Se	2.4, 3.1		9.9, 20	9.4+0.5
Sm	8.2, 7.1		60, 56	
Sn	NR, 95		NR, 911	
Sr	630, 610		1800, NR	(1380)
Th	7.4, 7.0	(3.0)	41, 45	(24)
Ti	670, 580	(800)	5000, 4400	
U	1.2, 0.8	1.4	10, 9.4	11.6+0.2
V	33, 32	35	220, 210	214+8
W	1.1, 0.7		6.6, 6.4	
Yb	0.6, 0.5		4.8, 4.9	
Zn	63, 71	37	310, 240	210+20

NR - means that the level of interfering compounds was covering the metal of interest. Therefore, a reportable result was not possible.

TABLE 3-41PERCENT METHYLENE CHLORIDE EXTRACTABLE

<u>Sample</u>	<u>P.S. of Colorado⁽¹⁾</u>	<u>East Kentucky⁽¹⁾</u>
	<u>Test No. 16</u>	<u>Test No. 80</u>
10 μ m cyclone & probe	<0.1%	<0.1%
3 μ m cyclone	0.2%	<0.1%
1 μ m cyclone & final filter	0.4%	0.2%
XAD-2 Resin	<0.1%	<0.1%

(1) Both tests are baseline operating conditions.

TABLE 3-42PNA RECOVERY DATA FOR SASS TRAIN SAMPLES

<u>Sample</u>	<u>% C-14 Recovery¹</u>
<u>P.S. Company of Colorado</u>	
<u>Test 16 (Baseline)</u>	
1 μ m cyclone	98
3 μ m cyclone	81
10 μ m cyclone	7
XAD-2	64
<u>E. Kentucky</u>	
<u>Test 80 (Baseline)</u>	
1 μ m cyclone	46
3 μ m cyclone	41
10 μ m cyclone	7
XAD-2	75

¹ Assuming 88% counting efficiency.

The PNA data for those samples with good carbon-14 recovery are listed in Table 3-43. It should be noted that GC/UV measurement was not made on the Test 16 (Baseline test at P.S. of Colorado) cyclone samples. The reason for this was that the UV spectra of the 1 μ m and 3 μ m cyclone samples showed only the carbon-14 labeled standards and no other PNA's. Less than numbers were then calculated for the other PNA's based on recovery of the labeled standards.

In all cases the requested detection limit of 2 μ g/m³ was achieved. It was surprising, however, to see that most of the PNA's were on the 1 μ m cyclone catch, while the XAD-2 resin had only less than amounts. One would have predicted that due to the high oven temperature (400°F) of the cyclones the volatile PNA material would have condensed in the XAD-2 module (70°F) and not on the 1 μ m cyclone particulate.

D. Anions

The anion data for the cyclone and condensate samples are presented in Tables 3-44 and 3-45, respectively. The data suggest that lower anion amounts were present on the particulate samples collected under low NO_x than baseline conditions. The reverse was true, however, for the condensate samples.

E. Organochlorides

Extractable organochloride data for Baseline Test No. 16 at P.S. of Colorado samples is presented in Table 3-46. It should be mentioned that the values for the particulate samples could be erroneously high due to incomplete solvent exchange of the methylene chloride with pentane. Also, since low μ g/m³ total organohalide amounts are presented in Table 3-46, the likelihood of a single compound or class of compounds such as PCB's being present above the requested 2 μ g/m³ detection limit is remote.

3.7.5 Conclusion

SASS train samples from East Kentucky Power Cooperative, Inc. and Public Service of Colorado Power Plants were analyzed for metals, PNA's, and anions. The analytical results presented in this section show that the low NO_x operating conditions at the Colorado Plant did not significantly reduce all metallic emissions.

PNA concentrations were all below the requested 2 μ g/m³ levels. However, low amounts of PNA's were present (0.1-0.8 μ g/m³) on the particulate samples from the Kentucky plant. Poor PNA extractability precluded accurate analysis of the 10 μ m cyclone samples. At the P.S. Company of Colorado Plant lower anion concentrations were obtained from particulate samples while higher values were detected on the condensate samples for the low NO_x operation than during baseline operation.

TABLE 3-43

PNA DATA FOR SASS TRAIN SAMPLES
(Results reported in $\mu\text{g}/\text{m}^3$)

Compound	P.S. Col	E. Ky	XAD-2 ^a	E. Kentucky		P.S. Colorado	
	XAD-2 Test 16	XAD-2 Test 80	Blank	1 μm Cyclone Test 80	3 μm Cyclone Test 80	1 μm Cyclone Test 16	3 μm Cyclone Test 16
	Base	Base		Base	Base	Base	Base
Fluoranthene	<0.098	<0.096	<0.027	0.55	<0.15	<0.085	<0.057
Pyrene	<0.082	<0.080	<0.022	0.62	<0.13	<0.070	<0.047
Benzo(a)anthracene	<0.046	<0.036	<0.012	0.13	0.02	<0.051	<0.034
Chrysene	<0.036	<0.036	<0.010	0.11	0.03	<0.036	<0.024
Triphenylene	<0.029	<0.031	<0.008	0.19	<0.01	<0.035	<0.023
Methyl Benz(a)anthracene	<0.072	<0.075	<0.020	<0.32	<0.11	<0.062	<0.042
DM/ET Benzo(a)anthracene	<0.072	<0.075	<0.020	<0.32	<0.11	<0.062	<0.042
Benzo (g,h,i)fluoranthene	<0.39	<0.39	<0.11	<1.67	<0.59	<0.33	<0.22
Benzo(b)fluoranthene	<0.16	<0.16	<0.045	<0.71	<0.25	<0.14	<0.094
Benzo(j)fluoranthene	<0.31	<0.31	<0.086	<1.4	<0.48	<0.27	<0.18
Benzo(k)fluoranthene	<0.46	<0.47	<0.13	<1.00	<0.36	<0.20	<0.13
Perylene	<0.21	<0.18	<0.058	0.76	<0.23	<0.13	<0.087
Benzo(a)pyrene	<0.23	<0.13	<0.059	0.65	<0.15	<0.18	<0.12
Benzo(e)pyrene	<0.21	<0.16	<0.055	<0.63	<0.22	<0.12	<0.083
Methyl Benzo(a)pyrene	<0.26	<0.27	<0.072	<1.1	<0.40	<0.22	<0.15
Methyl Benzo(e)pyrene	<0.18	<0.18	<0.049	<0.77	<0.28	<0.15	<0.10
Benzo(g,h,i)perylene	<0.29	<0.29	<0.081	<1.2	<0.41	<0.23	<0.15
Coronene	<0.026	<0.027	<0.007	<0.11	<0.041	<0.023	<0.015

^a Based on 177.4g XAD-2, 25 m³ air

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TABLE 3-44
PUBIC SERVICE COMPANY OF COLORADO
ANION CONTENT OF CYCLONE SAMPLES
(RESULTS REPORTED IN mg/m³)

	Test No.	
	14	16
	Low NO _x	Base
	3.5	6.6
SO ₄ - (Particulate Composite)	<0.3	<0.8
NO ₃ - (Particulate Composite)	0.70	0.98
F ⁻ (10 μm & Probe)	0.35	0.95
F ⁻ (3 μm Cyclone)	0.48	0.69
F ⁻ (1 μm & Final Filter)		

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TABLE 3-45
ANION CONTENT OF CONDENSATE SAMPLES
(RESULTS REPORTED IN mg/m³)

Anion	Test No.	P. S. Colorado		E. Kentucky	
		14	16	80	Base
		Low NO _x	Base		
Cl ⁻		0.85	0.27	37	
F ⁻		0.51	0.16	3.3	
CN ⁻		<0.2	<0.13	<0.19	
NO ₃ ⁻		<0.2	0.19	2.5	
SO ₄ ⁼		36	3.0	14	

TABLE 3-46
PUBLIC SERVICE COMPANY OF COLORADO
EXTRACTABLE ORGANOCHLORIDES
TEST 16 BASELINE

<u>Sample</u>	<u>Organochlorides</u> <u>($\mu\text{g}/\text{m}^3$)</u>
10 μm cyclone & probe	32
3 μm cyclone	7.5
1 μm cyclone & final filter	12
XAD-2 Resin	0.2
Blank ^a	2.3

^a The pentane blank has already been subtracted from the samples.

4. CONCLUSIONS

The overall conclusions derived from the Phase I and Phase II field test results are summarized in this section. The effects of combustion modifications for NO_x emission control on coal-fired, oil-fired, mixed fuel (coal-oil, coal-gas) fired boilers and gas and oil fired gas turbine gaseous emissions, particulate emissions, furnace water-wall corrosion and boiler performance will be discussed.

4.1 GASEOUS EMISSION MEASUREMENTS

In Section 3.1 of this report, the gaseous emission results obtained in field studies on each of seven power generation combustion sources were discussed. Appendix B contains a summary of the operating conditions and emission results for each test run. In this section, the conclusions based on these seven units plus the eight units tested in Phase I (5) are presented.

Tables 4-1 and 4-2 contain a summary of the NO_x emissions for nine coal-fired boilers under baseline and "low NO_x" operation. Three of the units are single wall-fired boilers: Rear wall-fired Widows Creek No. 5, front wall-fired Mercer No. 1 and front wall-fired Cooper No. 2. Two units are horizontally opposed-fired units; Gaston No. 1 and Comanche No. 2 boilers. The remaining four units are tangentially fired. Five of the units tested were equipped with special NO_x emission control devices. Ernest C. Gaston boiler No. 1 has been retrofitted with the Babcock and Wilcox dual register, low NO_x burners. Overfire air ports have been provided on three tangentially-fired boilers: Navajo No. 2, Comanche No. 1 and Barry No. 2 and on one wall-fired unit-Comanche No. 2. Mercer No. 1 is a wet-bottom fired unit while all the other are dry bottom units. Baseline emission data were also obtained on E. C. Gaston boiler No. 2 (a "sister" unit of Gaston No. 1) equipped with conventional pulverized coal, wall burners.

Gaseous measurements of O₂, NO_x and CO are listed in Tables 4-1 and 4-2 for baseline operation, "low NO_x-I" (modified firing operation at near full or full load) and "low NO_x-II" (modified firing operation from about 50 to 80% of full load). Baseline NO_x emission loads are listed at both actual excess air levels and calculated for 20% excess air so that comparisons between boilers can be made on the same operating basis. Note that correcting emissions to a 3% O₂ basis provides data on a constant dilution basis regardless of operating conditions. First conclusions will be discussed based on analysis of the wall-fired units listed in Table 4-1 and then, based on the tangentially fired boilers listed in Table 4-2.

The five wall-fired boilers (Widows Creek No. 5, Gaston No. 1, Mercer No. 1, Cooper No. 2 and Comanche No. 2) under baseline operating conditions, produced NO_x emission above the 301 ng/J (0.7 lb/10⁶ BTU) level of the original New Source Performance Standard (NSPS) for coal-fired steam

generators. However, under combustion modification operation (low NO_x -I), the dry bottom, wall-fired boilers, through low excess air-staged firing, overfire air ports, or in the case of Gaston No. 1, through use of dual register low NO_x Babcock and Wilcox burners, emitted NO_x below the level of NSPS under full load operation. The wet bottom, Mercer No. 1 unit required at 20% load reduction and low excess air-staged firing operation to reduce NO_x emissions below $0.7 \text{ lbs}/10^6 \text{ BTU}$ from its high baseline value of $1.88 \text{ lbs}/10^6 \text{ BTU}$. It should be noted that the two units equipped with special NO_x control devices (Gaston No. 1 with low NO_x designed burners and Comanche No. 2 with overfire air ports) experienced an average of 57% reduction over baseline operation at full load. Baseline emissions of 600 ppm measured on the No. 2 boiler at the Gaston Station (a sister unit) were reduced to 278 ppm (a reduction of 52%) as measured on the No. 1 boiler which had been retrofitted with B&W's low NO_x , dual register burners. Baseline emissions of 726 ppm on the Comanche No. 2 boiler equipped with overfire air ports, were reduced by staging the firing pattern and low excess air operation to 278 ppm, a reduction in emissions of 62 percent.

The five wall-fired units were capable of further reduction in NO_x emissions under reduced load operation. At reduced load (by 20%), Widows Creek boiler No. 5 produced NO_x emissions as low as $179 \text{ ng}/\text{J}$ (305 ppm) in short term tests, i.e., 49% below the baseline NO_x level at full load. At 70% of full load, Gaston boiler No. 1 equipped with Babcock and Wilcox dual register burners, reduced NO_x emissions to $78 \text{ ng}/\text{J}$ (182 ppm) or 69% below Gaston boiler No. 2 (a sister boiler equipped with conventional burners) under baseline operation. At 83% of full load, Cooper No. 2 unit, under low excess air, staged operation reduced NO_x emissions to $205 \text{ mg}/\text{J}$ (350 ppm) or 37% below the baseline level. Comanche No. 2 unit, operated at 76% of full load and 80% open overfire air ports produced $181 \text{ ng}/\text{J}$ (310 ppm) NO_x or 57% below full load, baseline operation. For the wet bottom Mercer boiler No. 1 operated at 20% reduced load, staged combustion with low excess air reduced NO_x emissions by 74% from the baseline emission level.

Under full load, baseline operation (cooling air only), the three tangentially fired boilers that are equipped with overfire air ports met the $301 \text{ ng}/\text{J}$ ($0.7 \text{ lb}/10^6 \text{ BTU}$) NSPS for NO_x . Morgantown boiler No. 1 (without overfire air ports) emitted NO_x slightly above this level under baseline firing conditions with coal fuel. Modified firing using the overfire air ports at low overall excess air resulted in reductions of 37 to 45% in NO_x emissions. Staged firing of Morgantown boiler No. 1 reduced NO_x emissions by 27% for this particular unit. Comparison of baseline NO_x emissions normalized to 20% excess air for the three boilers equipped with OFA to those measured on four tangentially fired boilers in previous ER&E field test studies show an 18% NO_x reduction due to cooling air. Thus, tangentially fired boilers designed with NO_x control devices (overfire air ports) are capable of considerably larger NO_x emission reductions than conventional tangentially fired boilers at full load in the same manner previously discussed for wall-fired boilers.

The ranges of NO_x emissions measured under normal firing conditions as a function of excess air level (% O_2 in the flue gas) are shown in Figure 4-1. The wet bottom Mercer No. 1 boiler (labeled M) produced much higher baseline NO_x emissions than the dry bottom, coal-fired boilers. This high NO_x level is caused by the unusual furnace design of this boiler in which pulverized coal can be burned at low loads with a wet bottom furnace. The flat furnace floor is relatively close to the bottom row of burners so that unusually high gas temperatures are maintained in the bottom of the furnace in order to maintain the slag in a molten state.

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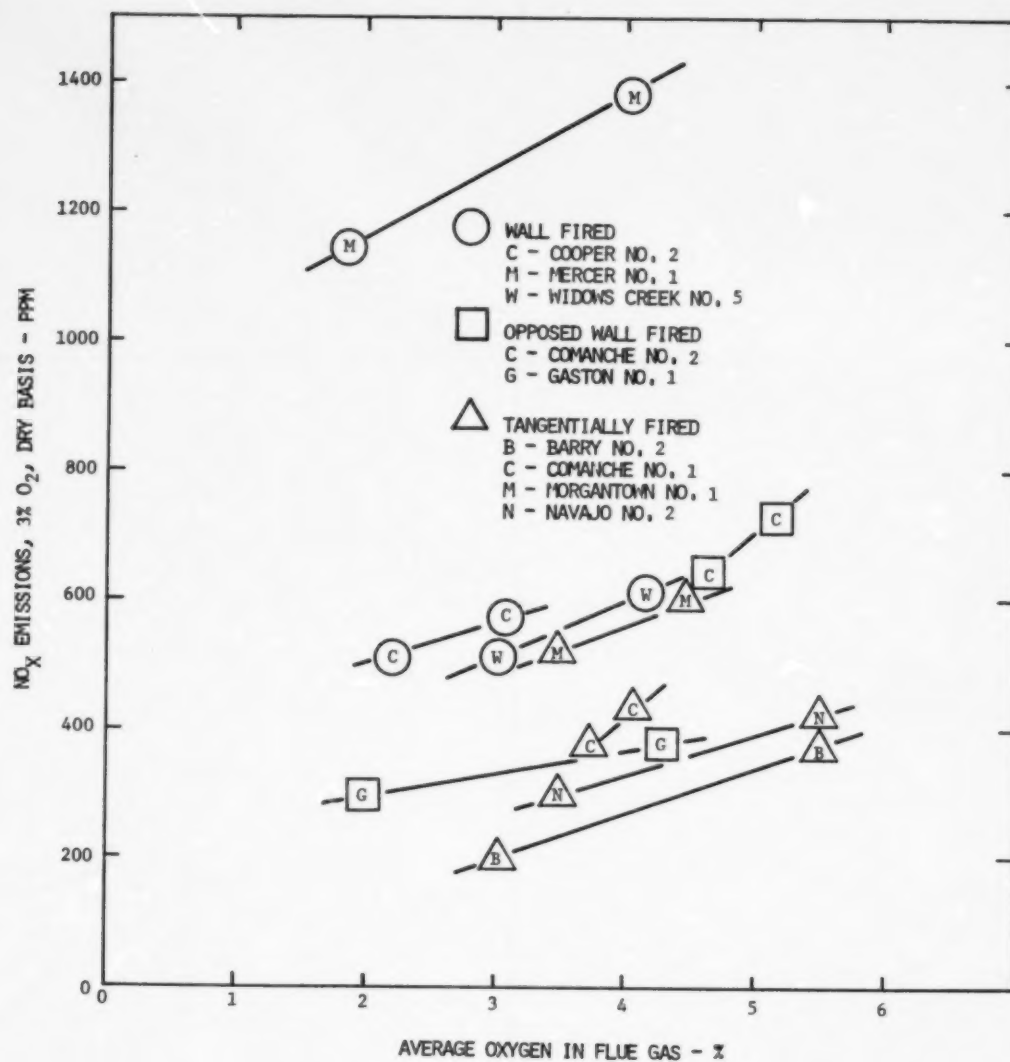


Figure 4-1. NO_x emissions vs average oxygen in flue gas from coal-fired boilers under normal firing operation.

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As discussed in Section 3.1, excess air had a significant effect on NO_x emissions for each boiler under normal firing operation. The relationship of NO_x vs O_2 is shown in Figure 4-1. With the exception of Comanche boilers No. 1 and No. 2 (which had limited operating flexibility for changing excess air level) the slopes, calculated by least squares, of these lines are fairly consistent. However, the actual NO_x levels vary because of differences in boiler size, type of firing, type and composition of coal fired, and other factors.

Figures 4-2 and 4-3 show the overall relationship between NO_x emissions and excess air level (% O_2 in flue gas), on a consistent basis for normal firing and modified firing operation for the seven coal-fired boilers tested in this program.

Figure 4-2 is a plot of "normalized" NO_x emissions expressed as the fraction of baseline NO_x emissions (full load and 20% excess air) as a function of the average O_2 concentration measured in the flue gas for normal firing conditions. The solid lines shown for each boiler are based on the least-squares, linear regression analysis of all full load test runs made under normal firing operation (all burners firing coal and with closed overfire air ports). With the exception of the Comanche boilers No. 1 and No. 2 mentioned above and Barry No. 2, all of the lines fit within a relatively narrow band.

Figure 4-3 is a plot of "normalized" NO_x emissions (expressed as the fraction of baseline NO_x emissions at full load and 20% excess air) vs the average O_2 concentration measured in the flue gas under modified combustion operating conditions. Thus, the ordinates are identical in Figures 4-2 and 4-3. However, the least squares regression lines of Figure 4-3 do not necessarily pass through the normalized NO_x value of 100% at 3.6% O_2 , as they must, by definition, in Figure 4-2.

Figure 4-3 indicates the strong effect of lowering the excess air on NO_x emissions when boilers are operated in the staged combustion mode. The slopes of these lines are very similar except for Morgantown boiler No. 1 (which was fired with a mixture of coal and oil), Barry No. 2 unit (which has overfire air ports located relatively far from the top row of active burners) and Comanche No. 2 unit with limited excess air flexibility. It should be noted that all of the boilers tested had actual baseline NO_x emission rates higher than those normalized to 20% excess air (used for constructing Figure 4-3), and that optimized, modified firing operation generally produced lower NO_x operation than shown by the least squares lines which covered all test runs. Mercer boiler No. 1 (ME), the only wet bottom boiler tested in this program, had unusually high baseline NO_x emission levels. This is reflected by the large reduction obtained under 80% load, modified firing operating conditions. An additional point to recall again is that three of the tangentially fired boilers are equipped with overfire air ports, which resulted in an average 18% reduction from normalized baseline NO_x emissions compared to the results for the tangentially fired boilers tested previously (2). This reduction in baseline NO_x emissions is due to the use of cooling air through the overfire air ports.

Three large (50 MWe rated) General Electric model MS 7000, gas turbines were tested in this program. Table 4-3 contains a summary of the

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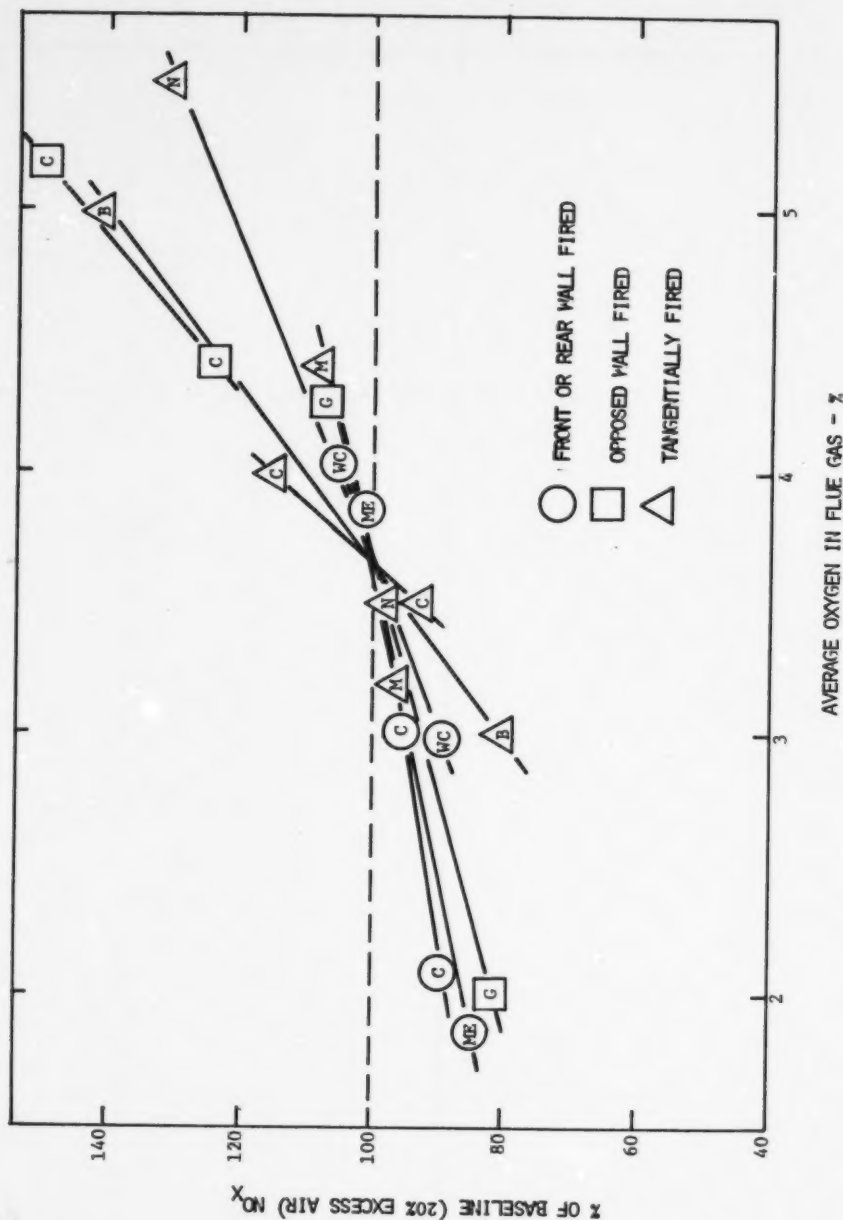


Figure 4-2. Effect of excess air level on NO_x emissions for coal fired boilers under normal firing operations.

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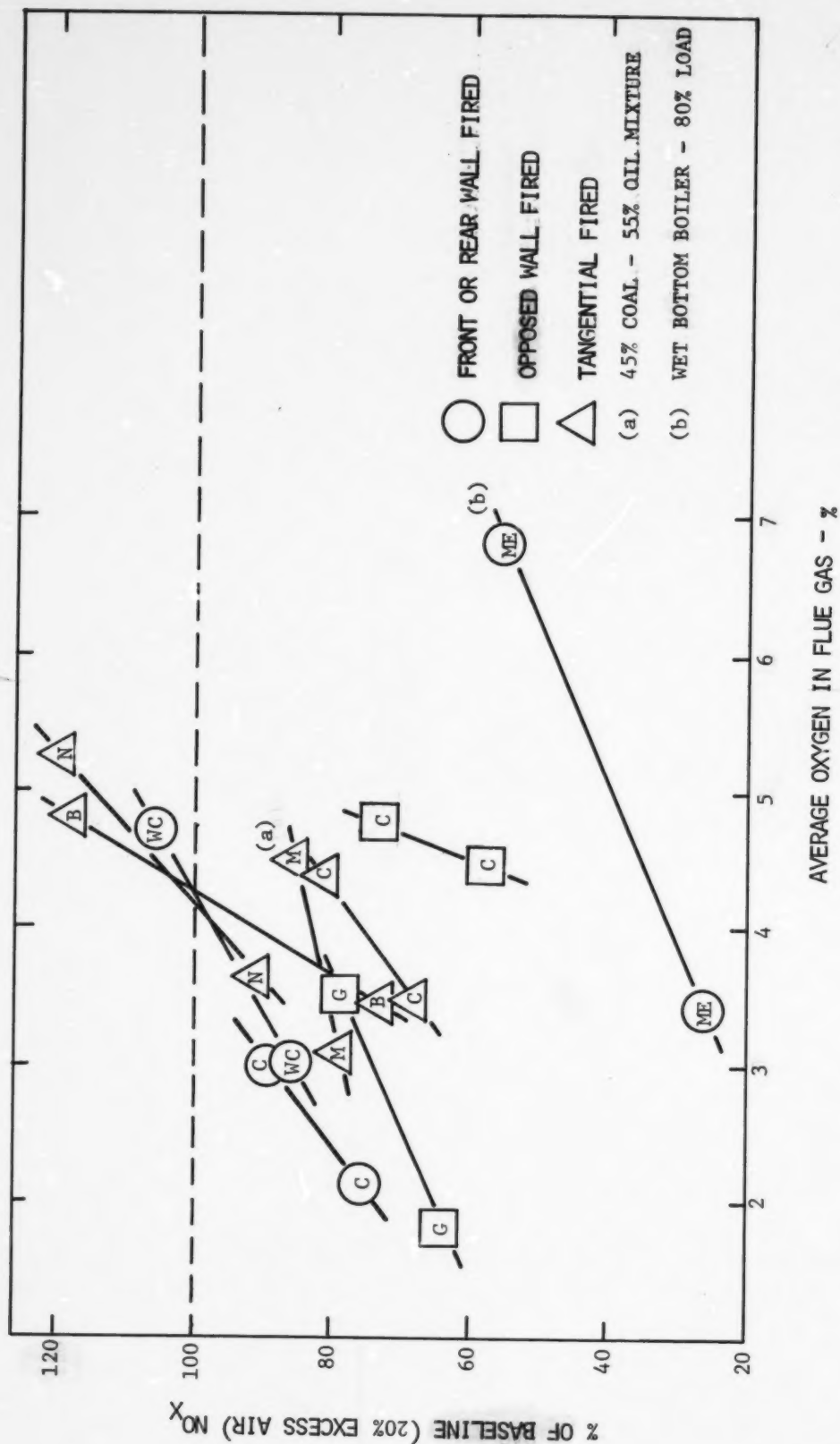


Figure 4-3. Effect of excess air on NO_x emissions of coal fired boilers under modified firing conditions.

NO_x, CO and gaseous HC emissions from these units for base operating conditions, as well as maximum water injection operation, for each load tested. The Morgantown unit did not have water injection capabilities; consequently, load reduction was the only operating variable on this unit.

Each of the three operating variables (fuel, load, and water injection) had a significant effect on the level of NO_x emissions from gas turbines. At full load, uncontrolled NO_x emissions averaged 44% lower with gas firing than with oil firing. Fuel nitrogen probably accounts for this change. NO_x emissions reduced linearly with load with both fuels but not on a 1 to 1 relationship. Thus, an 81% reduction in load produced a 38% NO_x reduction on the Morgantown unit; a 61% reduction in load on Wharton No. 42 produced a 43% NO_x emission reduction, and a 63% load reduction produced a 42% NO_x emission reduction on Wharton No. 43 firing gas. Water injection was the most important operating variable. At peak load (55 MWe), 1.9% water injection (% of combustion air) reduced NO_x emissions by 85% on Wharton Unit No. 43 firing natural gas while a 90% reduction resulted from a 2.3% water injection on Wharton Unit No. 42 firing No. 2 fuel oil.

The results obtained on mixed fuel-fired boilers(3) indicate that NO_x emission levels increased as the fraction of coal in coal-oil and coal-gas mixtures increases. However, the relationship between NO_x emissions and fuel coal content is not linear. Additional test data are required to establish a more reliable correlation for predicting NO_x emissions from mixed fuel fired units than the single assumption of linear dependence.

This section can be summarized as follows:

- Conventional wall and tangentially fired boilers that were not designed with special NO_x reduction features did not meet the original NSPS of 0.7 lb/10⁶ BTU for NO_x emissions under full load, baseline operation.
- Wall and tangentially fired boilers designed with NO_x reduction features such as low turbulence, dual register burners or overfire air ports were capable of meeting the NSPS for NO_x emissions under baseline operations.
- A wall-fired boiler (Gaston No. 1) retrofitted with Babcock and Wilcox, dual register burners emitted substantially less NO_x (377 ppm vs 591 ppm or -36%) than a similar boiler equipped with conventional burners.
- Three tangentially fired boilers equipped with overfire air ports were capable of reducing NO_x emissions by 37 to 45% under low excess air, staged firing operation (282 ppm vs 492 ppm, 261 ppm vs 417 ppm and 198 ppm from 341 ppm). A horizontally opposed fired boiler equipped with overfire air ports and compartmentalized windboxes reduced NO_x emissions by 62% (278 vs 726 ppm).
- Low excess air, staged firing operation on conventional wall fired units reduced NO_x emissions significantly on both dry and wet bottom units. The dry bottom units met the NSPS for NO_x emissions at full load under this operation while the wet bottom unit (with extremely high baseline emissions) was forced to reduce load to meet the 0.7 lb/10⁶ BTU NO_x emissions standard for new boilers.

- NO_x emissions increased from mixed-fuel fired boilers as the fraction of coal in coal-oil and coal-gas mixtures increased. However, the relationship between NO_x emissions and fuel coal content was not linear in the two units tested to date.
- The firing pattern used in low excess air, staged firing operation in boilers without overfire air ports, had a significant influence on the level of NO_x reduction obtained. Firing patterns utilizing top burners on air only, were more effective than firing patterns with middle or lower row burners on air only. In addition, the use of maximum secondary air register openings on air only burners while simultaneously reducing air register openings on operating burners had a beneficial effect on the level of NO_x emissions.
- Large gas turbines firing gas and fuel oil were capable of reducing NO_x emissions (15% O_2 dry basis) by 85% (11 ppm vs 74) and 90% (13 ppm from 127 ppm) respectively by use of water injection. NO_x emissions from oil fueled gas turbines were 44% higher than NO_x emissions from a similar size gas-fired gas turbine (73 ppm vs 130 ppm).

TABLE 4-1

SUMMARY OF NO_x EMISSIONS FOR PULVERIZED COAL, WALL-FIRED BOILERS

Boiler-Type of Firing (a)	Operating Mode (Gross Load - MWe)	% O ₂	NO _x Emissions		ppm CO (3% O ₂)
			ppm (3% O ₂)	Lb. 10 ⁶ Btu	
1. Widows Creek No. 5-RW	Base "Low NO _x - I" "Low NO _x - II"	- 125 - 125 - 100	597(567)(b) 468 305	0.81 0.64 0.41	29 88 285
2. Ernest C. Gaston No. 1-HO (Low NO _x Burners)	Base (No. 2 Unit) - 270 "Low NO _x - I" "Low NO _x - II"	4.0 3.2 5.3	591(491)(b) 278 182	0.80 0.38 0.25	36 65 329
3. Mercer No. 1-FW	Base "Low NO _x - I" "Low NO _x - II"	3.9 3.4 3.4	1383(1354)(b) 356 351	1.88 0.48 0.48	22 218 455
4. Cooper No. 2-FW	Base "Low NO _x - I" "Low NO _x - II"	3.1 2.6 2.6	557(575)(b) 483 350	0.76 0.66 0.48	30 61 16
5. Comanche No. 2-HO (Overfire Air Ports)	Base "Low NO _x - I" "Low NO _x - II"	5.2 4.5 5.0	726(488)(b) 278 310	0.99 0.38 0.42	19 63 16

(a) Types of Firing: RW, rear wall; HO, horizontally opposed; FW, front wall.

(b) Baseline NO_x emissions calculated for 20% excess air operation.

TABLE 4-2

SUMMARY OF NO_x EMISSIONS FOR PULVERIZED COAL, TANGENTIALLY FIRED BOILERS

Boiler	Operating Mode (Gross Load - MWe)	% O ₂	NO _x Emissions		
			ppm (3% O ₂)	Lb. 10 ⁶ BTU	ng/J
1. Navajo No. 2 (Overfire Air Ports)	Base - 800 "Low NO _x - 1" - 802	4.8 3.6	492(400)(a) 282	0.67 0.38	288 165
2. Comanche No. 1 (Overfire Air Ports)	Base - 323 "Low NO _x - 1" - 333	4.0 3.7	417(370)(a) 261	0.57 0.35	244 153
3. Barry No. 2 (Overfire Air Ports)	Base - 130 "Low NO _x - 1" - 129	4.9 3.3	341(250)(a) 189	0.46 0.26	199 111
4. Morgantown No. 1	Base (b) - 570 "Low NO _x - 1" - 572	4.9 4.7	552(534)(a) 403(c)	0.75 0.55	323 236
					ppm CO (3% O ₂)
					64 330
					27 35
					22 49
					21 20

(a) Baseline NO_x emissions calculated for 20% excess air operation.

(b) Fuel burned = 93% coal, 7% oil.

(c) Fuel burned = 74% coal, 26% oil.

TABLE 4-3

SUMMARY OF NO_x, CO AND HC EMISSIONS FOR GAS AND OIL-FIRED GAS TURBINES

Gas Turbine	Fuel Burned	Operating Mode -Gross Load, MWe	Emissions				
			O ₂	NO _x	CO	HC	
			% (15% O ₂)	Lbs. 10 ⁶ BTU (15% O ₂)	ppm (15% O ₂)	ppm (15% O ₂)	ppm (15% O ₂)
1. Morgantown Station Gas Turbine No. 3	No. 2 Fuel Oil	Base	14.7	0.58	224	81	5
	Base	- 48	15.2	0.55	214	30	6
	Base	- 25	17.3	0.47	182	4	10
	Base	- 10	17.9	0.36	138	4	24
2. Wharton Station Gas Turbine No. 42	No. 2 Fuel Oil	Base	15.3	0.50	214	4	3
	23% H ₂ O	- 51	14.6	0.05	22	53	2
	Base	- 40.0	16.5	0.41	178	3	3
	1.5% H ₂ O	- 37.5	16.4	0.07	29	142	20
	Base	- 20.0	17.3	0.03	121	19	3
	0.8% H ₂ O	- 20.0	17.4	0.07	31	114	19
3. Wharton Station Gas Turbine No. 43	Natural Gas	Base	15.5	0.26	112	4	2
	1.9% H ₂ O	- 56	15.1	0.04	17	60	51
	Base	- 43	16.0	0.22	95	4	4
	0.5% H ₂ O	- 43	16.0	0.12	52	7	4
	Base	- 30	17.5	0.23	97	18	5
	0.75% H ₂ O	- 30	17.6	0.04	15	336	131
	Base	- 20	18.1	0.15	64	42	10

4.2 Side Effects of Low NO_x Combustion Modifications

Field tests in the Phase I and Phase II programs placed increased emphasis on testing for potential adverse side effects of low NO_x firing methods. Sections 3.2 through 3.5 of this report discuss the testing during Phase II for the effects of low NO_x operation on particulates, furnace corrosion (via probes), sulfur oxides, and boiler efficiency. Overall conclusions regarding these side effects (from the Phase I and Phase II efforts) are summarized here.

Particulate Mass Emissions

Results of the Phase I investigations noted a tendency, in some cases, toward increased particulate mass emissions with low NO_x operation, observing that the magnitude of any increases or decreases in dust loading were not significant. Tests in the Phase II program showed no significant differences in mass emissions between "low NO_x" and baseline operation. The overall conclusion from these investigations is that where differences exist they are minimal in magnitude and no appreciable effect on electrostatic precipitator collection efficiency or performance would be expected due to changes in particulate mass emissions.

Particle Size Distribution

Data obtained on particulate particle size distribution in the Phase II program closely approximate the data developed in the Phase I field tests, i.e., no significant differences were detected in size distribution determinations under "low NO_x" firing conditions compared to baseline operation. Based on the results of these investigations it is concluded that "low NO_x" combustion modification control techniques did not affect particulate emission particle size distribution significantly and, as a result, should not materially affect electrostatic precipitator or mechanical collector efficiency.

Furnace Tube Corrosion

Data and information developed in the Phase I program investigated furnace tube corrosion via probes exposing coupons for 300 hours to baseline and "low NO_x" firing conditions. In the Phase I program and in the prior tests there was evidence that under some conditions "low NO_x" firing atmospheres resulted in somewhat higher coupon corrosion rates. However, no major increases in corrosion were observed for coupons exposed to low NO_x firing conditions and a major conclusion was that the corrosion probing data obtained, at the least, provides confidence that catastrophic corrosion will not occur as a result of combustion modifications to control NO_x emissions.

Corrosion data obtained in the Phase II program at 300 hour exposure again provided similar data. Low NO_x conditions showed somewhat higher corrosion rates than for baseline operation but the differences were not significant.

In the long term corrosion test conducted on Gulf Power Company's No. 7 boiler at the Crist Station, corrosion probe testing was more extensive than in previous programs. The effect of corrosion with time was investigated by exposing probes for 30 hours, 300 hours and up to 1000 hours to show initial, intermediate and long term corrosion effects. Conclusions of these investigations are:

- Corrosion rates developed via corrosion probes decreases with exposure time through 1000 hours approaching an asymptote above 450 hours exposure.
- Corrosion probes exposed for short terms (up to 30 hours) within the burner areas in the furnace sidewalls experience significantly greater corrosion rates than probes exposed outside the burner levels under low NO_x firing conditions. A similar trend is indicated for baseline operating conditions but more data is needed to reach firm conclusions.
- Probes exposed for periods of 300 to 1000 hours experienced no significant differences in corrosion rates due to furnace location (burner vs. nonburner area) or furnace operating mode (baseline vs. low NO_x firing).
- Effective correlation of actual long-term furnace tube corrosion rates require corrosion probe exposure of a minimum of 450 hour exposure.

(More comprehensive discussion of the Crist work will be forthcoming. A separate report describing the long term corrosion work at Crist in considerable detail will issue in the near future.)

Boiler Performance

Calculations of boiler efficiency from the data developed under baseline and "low NO_x " firing conditions in the Phase I and Phase II efforts show that "low NO_x " operation has no significant deleterious effect on boiler performance. The overall conclusion derived from the results of the Phase I, Phase II and prior programs is that combustion modifications for NO_x control, at the levels practiced in these investigations, produced no significant adverse effect on boiler efficiency.

5. REFERENCES

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APPENDIX A

CONVERSION FACTORS

English and Metric Units to SI Units

To Obtain	From	Multiply By	To Obtain ng/J of	Multiply Concentration in ppm at 3% O ₂ by
ng/J	lb/MBtu	430	Natural Gas Fuel	
ng/J	g/Mcal	239	CO	0.310
GJ·hr ⁻¹ ·m ⁻²	MBH/ft ²	11.356	HC	0.177
GJ·hr ⁻¹ ·m ⁻³	MBH/ft ³	37.257	NO or NO _x (as equivalent NO ₂)	0.510
GJ/hr	10 ³ lb/hr* or 106 Btu/hr	1.055	SO ₂ or SO _x	0.709
m	ft	0.3048	Oil Fuel	
cm	in	2.54	CO	0.341
m ²	ft ²	0.0929	HC	0.195
m ³	ft ³	0.02832	NO or NO _x (as equivalent NO ₂)	0.561
Kg	lb	0.4536	SO ₂ or SO _x	0.780
Celsius	Fahrenheit	$t_c = 5/9 (t_F - 32)$	Coal Fuel	
Kelvin		$t_K = 5/9 (t_F - 32) + 273$	CO	0.372
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895 \times 10^{-3})$	HC	0.213
Pa	psia	$P_{pa} = (P_{psia})(6.895 \times 10^{-3})$	NO or NO _x (as equivalent NO ₂)	0.584
Pa	iwg (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$	SO ₂ or SO _x	0.850

*lb/hr of equivalent saturated steam

APPENDIX A

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By	To Obtain ppm at 3% O ₂ of	Multiply Concentration in ng/J by
g/Mcal	ng/J	0.004186	Natural Gas Fuel	
10 ⁶ Btu	GJ	0.948	CO	3.23
MBH/ft ²	GJ·hr ⁻¹ ·m ⁻²	0.08806	HC	5.65
MBH/ft ³	GJ·hr ⁻¹ ·m ⁻³	0.02684	NO or NO _x	1.96
Btu	gm cal	3.9685 x 10 ⁻³	SO ₂ or SO _x	1.41
10 ³ lb/hr* or MBH	GJ/hr	0.948	Oil Fuel	
lb/MBtu	ng/J	0.00233	CO	2.93
ft	m	3.281	HC	5.13
in	cm	0.3937	NO or NO _x	1.78
ft ²	m ²	10.764	SO ₂ or SO _x	1.28
ft ³	m ³	35.314	Coal Fuel	
lb	Kg	2.205	CO	2.69
Fahrenheit	Celsius	$t_F = 9/5(t_C) + 32$	HC	4.69
	Kelvin	$t_F = 1.8K - 460$	NO or NO _x	1.71
psig	Pa	$P_{psig} = (P_{pa})(1.450 \times 10^{-4}) - 14.7$	SO ₂ or SO _x	1.18
psia	Pa	$P_{psia} = (P_{pa})(1.450 \times 10^{-4})$		
iwg (39.2°F)	Pa	$P_{iwg} = (P_{pa})(4.014 \times 10^{-3})$		

*lb/hr of equivalent saturated steam

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APPENDIX B
TABLE B-1
SUMMARY OF OPERATING AND EMISSION DATA - COOPER, BOILER NO. 2
(200 Mw, Front Wall, Pulverized Coal Fired)

Date and Run No. (1977)	Gross Load (MWe)	Operating Conditions				Flue Gas Measurements							Temp. Kelvin
		Firing Pattern(s)	Sec. Air Reg.		Excess Air Level	O ₂ %	PPM (3% O ₂ Dry)	NO _x Pounds Per 10 ⁶ BTU	Nanogram Per Joule	CO ₂ %	CO PPM (3% O ₂ Dry)	HC PPM (3% O ₂ Dry)	
			% Open	Top Row									
2/16-23 24 25	177 175 177	S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal	70 70 90	70 70 70	Normal Low Normal	3.0 1.8 3.1	580 464 578	0.79 0.63 0.78	339 271 338	15.6 16.4 15.4	9 28 15	0 0 0	600 594 603
2/17-2 2A 2B 5 6 206 15 174 16	217 216 217 206 206 174 172	S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal	70 70 70 88 86 100 100	70 70 70 70 70 70 70	Low Low Normal Low Low Normal Low	2.1 2.1 1.4 2.8 2.1 4.2 2.6	544 518 465 514 433 458 350	0.47 0.70 0.63 0.70 0.59 0.62 0.48	318 303 272 301 253 268 205	16.4 16.0 16.8 15.7 16.4 14.4 15.3	78 28 148 17 30 17 29	7 5 5 6 6 17 6	614 615 613 608 607 596 590
2/18-23A 13 14 177	190 186 178 177	S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal	80 80 80 80	70 70 70 70	Normal Low Normal Low	2.9 1.6 3.4 2.0	578 459 476 393	0.79 0.61 0.65 0.53	338 263 278 230	15.6 16.7 15.4 17.0	0 62 20 60	0 7 4 5	604 593 598 590
2/22-23B 26 27 28 29	180 180 179 120 118	S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal	78 70 70 70 70	70 70 70 70 70	Normal Low Low Normal Low	3.9 3.9 2.5 6.7 2.8	612 568 444 416 230	0.83 0.77 0.60 0.57 0.31	358 332 260 243 134	14.8 14.8 15.8 11.4 13.3	14 19 136 23 193	11 8 6 8 5	604 604 596 578 560
2/23-19 20 30 23C 31 32	181 174 140 181 117 115	S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal	70(a) 70(a) 70(a) 70 85(b) 85(b)	70 70 70 70 70 70	Normal Low Normal Normal Low Low	4.0 2.4 4.8 4.0 6.5 4.6	500 414 610 631 564 398	0.68 0.56 0.83 0.86 0.77 0.54	292 242 357 369 330 233	14.7 16.1 13.6 14.6 12.6 14.5	15 17 12 17 17 17	7 5 5 7 7 5	608 594 590 611 562 562
2/24-13A 16A 33 168 168 160 126 34	168 165 138 135 140 126 114	S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal S ₁ -All Burners Firing Coal	90(c) 90(c) 90(c) 90(d) 90(d) 90(d) 90(d)	70 70 70 70 70 70 70	Normal Low Normal Low Low Normal Low	4.1 3.4 6.1 3.9 3.2 5.8 5.0	496 433 467 466 373 531 560	0.68 0.59 0.64 0.63 0.51 0.72 0.76	290 253 273 273 218 311 327	14.6 14.9 12.4 13.1 15.6 13.1 13.6	22 36 14 24 27 21 15	10 6 5 5 5 5 4	601 594 588 587 573 575 566

(e) See Figure 3-1, page 14 for Cooper No. 2 mill-burner configuration.

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APPENDIX B

TABLE B-1 (cont'd.)

SUMMARY OF OPERATING AND EMISSION DATA - COOPER, BOILER NO. 2
(200 Mw, Front Wall, Pulverized Coal Fired)

Date and Run No. (1977)	Gross Load (Mw)	Operating Conditions				Flue Gas Measurements									
		Firing Pattern(a)	Sec. Air Reg. % Open		Excess Air Level	O ₂ %	PPH (% O ₂ , Dry)	Foundry Per 10 ³ BTU	Manogram Per Joule	CO ₂ %	CO (% O ₂ , Dry) ²	HC (% O ₂ , Dry) ²	Temp. Kelvin		
			Top Row	Other											
2/25-168	145	S ₁ -D ¹ Mill on Air Only	80	70	Normal	4.0	427	0.58	250	15.0	20	9	583		
35	118	S ₂ -D ¹ Mill Air Only; "A" Mill Off	80	70	Normal	5.7	519	0.71	304	11.3	20	9	576		
36	92	S ₁ -D ¹ Mill Air Only; "A" & "B" Mills Off	80(a)	70	Normal	7.9	586	0.80	343	10.7	80	0	564		
2/28-37	218	S ₁ -All Burners Firing Coal	75	70	Normal	2.5	568	0.77	332	15.3	127	-	627		
37A	218	S ₁ -All Burners Firing Coal	75	70	Normal	2.5	587	0.80	343	14.8	-	-	627		
3/3-38	190	S ₁ -All Burners Firing Coal	70	70	Normal	3.9	615	0.84	360	14.8	18	10	608		
3/8-39	208	S ₁ -All Burners Firing Coal	70	70	Normal	3.6	578	0.79	338	15.3	17	9	619		
40	210	S ₂ -D ¹ Mill Lean	80	60	Low	2.7	507	0.69	296	15.5	129	6	615		
3/9-41	178	S ₁ -All Burners Firing Coal	73	70	Normal	4.3	612	0.83	358	14.5	15	6	606		
3/10-42	212	S ₁ -all Burners Firing Coal	74	70	Normal	2.9	521	0.71	305	15.5	12	19	614		
42B	206	S ₁ -All Burners Firing Coal	74	70	Normal	3.6	549	0.75	321	15.1	14	18	614		
3/11-43	155	S ₁ -All Burners Firing Coal	74	70	Normal	5.4	576	0.79	337	13.2	9	6	593		
3/15-44	187	S ₁ -All Burners Firing Coal	70	70	Normal	4.1	612	0.83	358	13.4	10	7	604		
3/16-45	150	S ₁ -A ¹ Mill Off	70	70	Normal	5.2	631	0.86	369	13.5	14	12	598		
46	150	S ₁ -A ¹ & "A" Mill Off	70	70	Normal	5.2	632	0.86	370	13.1	13	10	598		
3/17-47	200	S ₁ -All Burners Firing Coal	70	70	Normal	3.6	578	0.79	338	15.0	11	6	614		
48	196	S ₂ -D ¹ Mill Lean	70	70	Low	2.1	437	0.59	256	16.3	65	3	603		
3/22-49	227	S ₁ -All Burners Firing Coal	75	70	Low	2.5	505	0.70	296	16.2	31	3	620		
3/23-50	205	S ₁ -All Burners Firing Coal	90	55	Normal	4.1	581	0.79	340	14.1	11	4	613		
50A	205	S ₁ -All Burners Firing Coal	90	55	Normal	3.5	580	0.80	345	15.3	10	5	613		
51	200	S ₂ -D ¹ Mill Lean	90	55	Low	2.6	496	0.66	290	15.8	14	5	605		
3/24-52	147	S ₁ -D ¹ Mill Lean; "B" Mill Off	90	55	High	5.3	572	0.78	335	13.5	14	6	586		
53	130	S ₁ -D ¹ Mill Lean; "B" Mill Off	90	55	Low	2.4	382	0.52	223	16.1	15	5	564		
54	130	S ₁ -D ¹ Mill Lean; "B" Mill Off	90	55	High	5.9	550	0.75	322	12.9	23	7	581		
55	136	S ₁ -D ¹ Mill Lean; "B" Mill Off	90	55	Low	4.5	485	0.66	284	14.5	96	6	571		
3/25-56	186	S ₂ -D ¹ Mill Lean	90	55	Normal	3.9	503	0.68	294	14.8	20	10	600		
57	184	S ₂ -D ¹ Mill Lean	90	55	Low	2.9	429	0.58	251	15.8	48	7	595		
58	132	S ₁ -D ¹ Mill Lean; "C" Mill Air Only	90	55	Normal	6.8	491	0.87	287	12.1	24	9	587		
59	123	S ₁ -D ¹ Mill Lean; "C" Mill Air Only	90	55	Low	5.0	382	0.52	223	13.6	24	11	570		
3/26-60	123	S ₁ -D ¹ Mill Air Only; A Off	90	70	Normal	6.5	490	0.67	287	12.1	15	20	578		
3/29-61	170	S ₂ -D ¹ Mill Lean	90	55	Normal	4.0	530	0.72	310	14.6	12	14	602		
62	170	S ₂ -D ¹ Mill Lean	90	55	Normal	4.2	522	0.71	305	14.6	15	2	599		
3/30-63	166	S ₂ -D ¹ Mill Lean	90	55	Normal	4.6	549	0.75	321	14.2	14	13	596		
64	16	S ₂ -D ¹ Mill Lean	90	55	Low	2.6	431	0.59	252	16.2	15	10	583		
3/31-65	173	S ₁ -D ¹ Mill Lean	90	55	Normal	5.0	594	0.81	347	13.8	15	12	599		
66	125	S ₂ -D ¹ Mill on Air Only	90	55	Normal	6.7	516	0.70	302	11.6	19	13	578		
67	125	S ₁ -D ¹ Mill on Air Only	92	55	Low	4.8	413	0.56	242	13.8	22	13	566		

(a) See Figure 3-1, page 14 for Cooper No. 2 mill-burner configuration.

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APPENDIX B

TABLE B-1 (cont'd.)

SUMMARY OF OPERATING AND EMISSION DATA - COOPER, BOILER NO. 2
(200 MWe, Front Wall, Pulverized Coal Fired)

Date and Run No. (1977)		Gross Load (MWe)	Operating Conditions				Flue Gas Measurements										Temp. Kelvin
			Firing Pattern(a)	Sec. Air Reg.		Excess Air Level	O ₂ %	PPH (3% O ₂ , Dry) ²	NO _x Pounds Per 10 ⁶ BTU	Nanogram Per Joule	CO ₂ %	CO PPH (3% O ₂ , Dry) ²	HC PPH (3% O ₂ , Dry) ²				
				Top Row	Other												
4/1-68	191	S ₁ -All Burners Firing Coal	92	55	Normal	3.3	580	0.79	339	14.6	14	25	606				
69	199	S ₁ -All Burners Firing Coal	90	55	Normal	2.8	541	0.74	316	15.2	15	16	605				
70	148	S ₂ -All Mill on Air Only	90	55	Normal	5.0	514	0.70	301	12.7	18	21	585				
71	147	S ₂ -All Mill on Air Only	90	55	Low	4.5	456	0.62	267	13.6	20	13	581				
72	138	S ₁₅ -All Mill Lean, "A" Mill Off	90	55	High	5.2	582	0.79	340	12.8	18	11	586				
73	138	S ₁₅ -All Mill Lean, "A" Mill Off	90	55	Normal	4.4	534	0.73	312	14.4	19	10	579				
4/14-74	190	S ₂ -All Mill Lean	100	55	Low	2.6	509	0.69	298	15.7	61	12	-				
4/15-75	190	S ₂ -All Mill Lean	100	55	Low	2.6	518	0.70	303	16.0	18	15	601				
75A	190	S ₂ -All Mill Lean	100	55	Low	2.7	502	0.68	294	15.8	14	3	601				
75B	190	S ₂ -All Mill Lean	100	55	Low	2.5	461	0.63	270	16.0	21	8	601				
75C	190	S ₂ -All Mill Lean	100	55	Low	2.2	485	0.66	284	16.7	294	10	601				
76	205	S ₁ -All Burners Firing Coal	71	70	Low	2.1	511	0.70	299	16.7	20	9	602				
76A	205	S ₁ -All Burners Firing Coal	71	70	Low	2.4	524	0.71	306	16.4	24	10	602				
76B	205	S ₁ -All Burners Firing Coal	71	70	Low	2.1	513	0.70	300	16.7	33	6	602				
76C	205	S ₁ -All Burners Firing Coal	71	70	Low	2.2	517	0.70	302	16.7	29	11	602				
4/19-77	206	S ₁ -All Burners Firing Coal	74	70	Normal	2.6	510	0.69	298	15.8	-	30	610				
77A	206	S ₁ -All Burners Firing Coal	74	70	Normal	2.4	522	0.71	305	15.5	-	19	610				
77B	206	S ₁ -All Burners Firing Coal	74	70	Normal	2.6	546	0.74	319	16.1	-	17	610				
77C	206	S ₁ -All Burners Firing Coal	74	70	Normal	2.5	540	0.73	316	15.8	-	17	610				
77D	206	S ₁ -All Burners Firing Coal	74	70	Normal	2.5	530	0.72	310	15.9	-	16	610				
78	203	S ₂ -All Mill Lean	95	70	Low	2.7	467	0.64	273	16.3	93	13	603				
78A	203	S ₂ -All Mill Lean	95	70	Low	3.0	492	0.67	288	15.8	32	8	603				
78B	203	S ₂ -All Mill Lean	95	70	Low	2.6	471	0.64	275	15.9	42	10	603				
78C	203	S ₂ -All Mill Lean	95	70	Low	2.6	482	0.66	282	15.8	131	8	603				
4/20-79	203	S ₁ -All Burners Firing Coal	75	70	Normal	2.7	520	0.71	304	15.9	22	16	613				
79A	203	S ₁ -All Burners Firing Coal	75	70	Normal	2.4	517	0.70	302	15.8	20	8	613				
79B	203	S ₁ -All Burners Firing Coal	75	70	Low	1.9	488	0.66	285	16.1	25	10	613				
79C	203	S ₁ -All Burners Firing Coal	75	70	Low	1.3	470	0.64	275	16.4	47	10	613				
5/4-80	154	S ₁₇ -All Mill Off	75	70	Normal	4.4	552	0.75	323	14.4	18	9	593				
5/9-81	190	S ₁ -All Burners Firing Coal	72	70	Low	2.1	481	0.65	281	16.5	17	8	605				
82	175	S ₂ -All Mill Lean	90	55	Low	1.8	438	0.60	256	16.6	38	8	608				
83	172	S ₂ -All Mill Lean	90	55	Low	2.1	447	0.61	261	16.0	31	13	599				

(a) See Figure 3-1, page 14 for Cooper No. 2 mill-burner configuration.

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APPENDIX B
TABLE B-2
SUMMARY OF OPERATING AND EMISSION DATA - COMANCHE, BOILER NO. 2
(350 MWe, Horizontally Opposed Pulverized Coal Fired)

Date and Run No. (1977)	Operating Conditions				Flue Gas Measurements									
	Gross Load (Mw)	Air Level	Firing Pattern		Secondary Air Registers (65% Open)	PPM (3% O ₂ , Dry)	NO _x			CO ₂	CO	HC PPM (3% O ₂ , Dry)	Temp. Kelvin	
			Symbol (a)	Over Fire Air Registers			Pounds per 10 ⁶ BTU	Nanogram Per Joule						
5/31-1 2	350 350	Normal Normal	S ₃ S ₂	60% Open 80% Open	4.6 4.4	382 317	0.52 0.43	223 185	14.9 15.0	144 204	5 0	630 625		
6/1-3 4	355	Normal	S ₅	40% Open	4.4	408	0.55	239	14.7	91	3	630		
5	356	Normal	S ₇	20% Open	4.9	574	0.78	236	14.4	22	5	639		
6	358	Normal	S ₆	0% Open	5.2	726	0.99	425	13.9	19	6	636		
	355	Normal	S ₁	100% Open	4.5	278	0.38	163	14.7	63	3	640		
6/2-7 8	352	High	S ₂	80% Open	5.2	433	0.59	253	13.9	18	4	656		
9	356	High	S ₇	20% Open	5.7	719	0.98	420	13.2	14	31	661		
10	354	High	S ₄	50% Open	5.7	527	0.72	308	13.6	14	5	658		
	350	Normal	S ₂	80% Open	4.8	348	0.47	204	14.7	68	4	642		
6/3-11 12	274	Normal	S ₅	40% Open	5.4	400	0.54	234	14.1	14	4	603		
13	275	Normal	S ₈	0% Open	5.6	607	0.83	355	13.5	12	3	608		
	272	Normal	S ₂	80% Open	5.0	310	0.42	181	14.2	16	2	608		
6/7-14 14A	348	High	S ₁	100% Open	4.8	356	0.48	208	14.1	80	4	683		
	348	Normal	S ₁	100% Open	4.7	325	0.44	190	14.3	140	4	694		
6/9-15A 15B	354	High	S ₆	30% Open	6.9	613	0.83	358	13.6	91	5	-		
	354	High	S ₆	30% Open	5.4	613	0.83	358	13.7	140	5	-		
6/14-16	336	Normal	S ₆	30% Open	4.9	489	0.67	286	13.2	20	0	-		

(a) Firing pattern symbols and overfire air register settings:
S₁-100% open, S₂-80% open, S₃-60% open, S₄-50% open, S₅-40% open, S₆-30% open, S₇-20% open and S₈-0% open (cooling only).

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APPENDIX B

TABLE B-3

SUMMARY OF OPERATING AND EMISSION DATA - SEWAREN, BOILER NO. 5
(330 MWe, Horizontally Opposed Oil Fired)

Date and Run No. (1976)	Operating Conditions				Flue Gas Measurements									
	Gross Load (MWe)	Excess Air Level	Firing Pattern		Flue Gas Recirc. to Furnace	Oil Add.	O ₂ %	PPM (3% O ₂ , Dry) ²	NO _x Pounds Per 10 ⁶ BTU	Nanograms Per Joule	CO ₂ %	CO PPM (3% O ₂ , Dry) ²	HC PPM (3% O ₂ , Dry) ²	Temp. Kelvin
			Symbol	Burners on Air only (a)										
9/3-1	280	Low	S1	31R	High	Off	2.4	270	0.35	151	13.4	12	3	571
2	288	Low	S1	31R	Low	Off	1.8	254	0.33	142	12.9	16	4	561
3	287	Normal	S1	31R	Low	Off	3.4	277	0.36	155	11.9	10	4	577
4	286	Normal	S1	31R	High	Off	3.5	311	0.40	174	12.7	14	5	593
9	288	Normal	S1	31F, 34F, 31R, 34R	High	Off	3.8	242	0.31	135	12.2	17	5	596
6	282	Low	S2	31F, 34F, 31R, 34R	High	Off	3.4	226	0.29	126	12.6	22	4	593
9/7-11	289	Normal	S3	32F, 33F, 31R, 32R, 33R	Low	Off	4.3	249	0.32	139	11.9	13	4	568
10	290	Low	S3	32F, 33F, 31R, 32R, 33R	Low	Off	3.2	216	0.28	121	13.0	20	5	568
13	285	Normal	S3	32F, 33F, 31R, 32R, 33R	Low	Off	4.7	232	0.30	130	12.0	15	5	567
8	290	Normal	S4	31F, 34F, 31R, 34R	Low	Off	4.0	226	0.29	126	12.4	15	12	569
7	291	Low	S2	31F, 34F, 31R, 34R	Low	Off	3.5	211	0.27	118	13.0	25	8	568
8A	288	Normal	S2	31F, 34F, 31R, 34R	Low	Off	4.4	241	0.31	135	12.0	17	9	566
12	282	Low	S4	32F, 33F, 31R, 32R, 34R	Low	Off	3.9	216	0.28	121	12.7	19	6	565
9/8-18	209	Low	S1	31R	High	Off	2.5	211	0.27	118	13.4	16	7	577
19	210	Normal	S1	31R	High	Off	6.0	286	0.37	160	10.6	14	7	577
48	286	Normal	S1	31R	Low	Off	4.1	285	0.37	159	12.5	13	10	586
21	280	Normal	S1	31R	Low	On	4.4	295	0.38	165	12.3	17	14	597
20	279	Low	S1	31R	Low	On	2.3	256	0.33	143	14.1	25	9	569
17	138	Normal	S6	31F, 32F, 33F, 34F, 31R, 32R, 33R, 34R	Low	Off	7.5	183	0.24	102	0.2	19	11	551
9/9-46	286	Normal	S1	31R	Low	Off	4.2	277	0.36	155	12.4	19	16	596
18	286	Low	S1	31R	Low	Off	2.1	243	0.32	136	14.1	22	8	596
14	145	Low	S1	31F, 34F, 22F, 23F, 31R, 34R, 22R, 31R	Low	Off	5.0	114	0.15	64	11.6	18	25	578
15	146	Normal	S5	31F, 34F, 22F, 23F, 31R, 34R, 22R, 31R	Low	Off	7.8	183	0.24	102	8.8	19	17	580
16	143	Low	S6	31F, 32F, 33F, 34F, 31R, 32R, 33R, 34R	Low	Off	5.0	131	0.17	73	11.1	17	10	577

(a) See Figure 3-8 Burner Configuration and Staged Firing Patterns (Sewaren No. 5 Unit).

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APPENDIX B

TABLE B-4

SUMMARY OF OPERATING AND EMISSION DATA -
T. H. WHARFON STATION, GAS TURBINE NO. 43
(50 MWe, Gas Fired)

Date and Run No. (1976)	Operating Conditions				Flue Gas Measurements									Temp. Kelvin
	Gross Load (MWe)	Ambient Air Temp. (Kelvin)	Inlet Air Relative Humidity %	Water Injected (% of Air)	O ₂ %	NO _x			Pounds Per 10 ⁶ BTU	Nanogram Per Joule	CO ₂ %	CO PPM (15% O ₂ , Dry)	HC PPM (15% O ₂ , Dry)	
						PPM (15% O ₂ , Dry)	PPM (3%, O ₂ , Dry)	PPM (15% O ₂ , Dry)						
5/11-1	52.5	295	73	0	15.5	71	212	0.25	16	3.1	2	2	784	
5/13-2	43.0	294	73	0	16.3	60	179	0.21	91	2.2	3	1	721	
3	20.0	295	63	0	18.1	40	120	0.14	61	1.6	41	3	592	
4	54.0	296	60	0	15.5	73	220	0.26	112	3.1	4	2	784	
5	55.5	295	60	0.75	15.1	32	97	0.12	30	3.2	6	5	784	
6	56.0	295	63	1.00	15.0	25	75	0.09	32	3.2	4	4	782	
7	55.0	296	60	0.50	15.0	40	119	0.14	61	3.1	5	3	784	
8	43.0	296	50	0.50	16.0	34	101	0.12	52	2.6	7	4	714	
9	43.0	295	50	0	16.0	62	186	0.22	95	2.5	4	4	726	
5/28-23	56.0	294	63	0	15.7	74	223	0.27	114	3.0	2	1	784	
24	57.5	295	59	1.90	15.1	11	34	0.04	17	3.2	60	51	780	
25	56.0	296	55	1.35	15.2	18	55	0.07	28	3.1	30	3	780	
26	55.0	296	58	0.75	15.2	32	96	0.11	49	3.0	6	2	782	
27	20.0	297	55	0	18.1	42	126	0.15	64	1.4	42	10	601	
28	30.0	297	54	0	17.5	64	192	0.23	97	1.7	18	5	648	
29	30.0	297	54	0.75	17.6	10	30	0.04	15	2.0	336	131	633	

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(PREVIOUSLY CEN. EPA FORM 257)

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APPENDIX B

TABLE B-5

SUMMARY OF OPERATING AND EMISSION DATA -
T. H. WHARTON STATION, GAS TURBINE NO. 42
(50 MWe, Oil Fired)

Date and Run No. (1976)	Operating Conditions				Flue Gas Measurements									
	Gross Load (MWe)	Ambient Air Temp. (Kelvin)	Inlet Air Relative Humidity %	Water Injected (% of Air)	O ₂		NO _x			Nanogram Per Joule	CO ₂	CO		Temp. Kelvin
					PPM (15% O ₂ , Dry)	%	PPM (3% O ₂ , Dry)	Pounds Per 10 ⁶ BTU	PPM (15% O ₂ , Dry)			%	PPM (15% O ₂ , Dry)	
10/14-10	40.0	295	50	0	106	317	0.41	178	3.2	3	3	710		
11	39.0	295	45	0.75	38	114	0.15	64	3.1	3	3	700		
12	37.5	295	47	1.50	17	52	0.07	29	3.1	142	20	677		
13	37.5	295	44	1.21	21	62	0.08	35	3.0	64	7	689		
14	51.0	296	39	0	127	382	0.50	214	3.8	4	3	789		
15	52.0	296	39	0.75	57	170	0.22	96	4.0	8	1	789		
16	53.5	297	34	1.50	29	88	0.11	49	4.3	9	1	787		
17	54.5	297	40	2.00	20	60	0.083	34	4.3	34	2	787		
18	55.5	297	37	2.30	13	40	0.05	22	4.4	53	2	787		
19	20.0	296	37	0	72	216	0.03	121	2.5	19	3	649		
20	19.5	297	27	0.50	25	75	0.10	42	2.5	60	7	634		
21	20.0	298	35	0.80	19	56	0.07	31	2.5	114	19	636		
22	0	298	36	0	38	115	0.15	65	1.3	145	25	527		

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APPENDIX B

TABLE B-6

SUMMARY OF OPERATING AND EMISSION DATA - CRIST STATION BOILER NO. 7
(500 Mc, HORIZONTALLY OPPOSED, PULVERIZED COAL FIRED)

Date and Test No.	Operating Data			Emissions Measurements									
	Gross Load	Excess Air Level	Second- Air Regist.	Firing Pattern	Visual Opacity	O ₂ %	ppm (5%) Dry	Pounds Per 10 ⁶ Btu	Manograms per Joule	CO ₂ %	CO PPM	HC PPM	Temp. Kelvin
3/1/76 31 1 2 488 2A 487 S1	475	Normal	70%	20 D Mill		5.5	846	1.13	485	15.5	16	0	0
	500	Normal	70%	24 None		4.3	913	1.22	523	15.5	16	0	0
	488	Low	70%	24 None	35%	3.2	797	1.06	457	15.3	15	0	0
	487	Low	70%	24 None	55%	2.1	696	.93	399	15.8	37	0	702
3/2/76 1A 4 3 508 S1	489	Normal	70%	24 None	60%	3.4	750	1.00	430	15.2	15	0	692
	510	Low	70/40	24 None	65%	2.6	702	.94	402	16.0	154	0	702
	508	Normal	70/40	24 None	55%	3.6	810	1.08	464	15.9	14	0	701
	466	Normal	70/40	24 None	50%	5.0	835	1.11	479	14.8	26	0	702
3/3/76 7 8 472 1B 480 S1	472	Low	70/40	24 None		3.3	746	.99	428	15.6	18	0	692
	480	Normal	70/40	24 None	60%	5.2	864	1.15	495	15.8	14	0	705
	400	Normal	70/40	20 F Mill	60%	6.6	720	.96	413	15.7	15	0	687
	393	Low	70/40	20 F Mill	50%	2.8	371	.49	213	15.6	54	0	669
3/5/76 23 24 190 S7	190	Normal	70/40	16 B&F Mills		7.9	712	.95	408	15.2	26	0	621
	190	Low	70/40	16 B&F Mills		4.9	483	.64	277	14.6	20	0	602
	420	Normal	70/40	20 C Mill		4.4	548	.73	314	15.5	12	0	701
	437	Normal	70/40	24 None		4.2	666	.89	382	15.5	12	0	702
3/8/76 7A 430 S2	430	Low	70/40	24 None		2.1	556	.74	319	15.4	45	0	687
	502	Normal	70/40	24 None		3.7	813	1.08	466	15.4	12	0	733
	415	Normal	70/40	20 C Mill		5.8	688	.92	394	14.6	16	0	688
	413	Low	70/40	24 C Mill		2.4	415	.55	238	15.2	71	0	681
3/11/76 1D 399 S1	399	Normal	70/40	24 None		6.1	809	1.08	464	14.7	45	0	693
	380	Normal	70/40	18* C Mill		6.6	693	.92	397	14.3	40	0	591
	380	Normal	70/40	20 C Mill		6.5	714	.95	409	15.1	46	0	690
	250	Normal	70/40	16 D&F Mills		6.2	421	.56	241	14.0	24	0	646
3/15/76 33 17 232 S6	232	Normal	70/40	16 C&F Mills		6.0	363	.48	208	14.8	36	0	652
	259	Low	70/40	16 C&F Mills		4.0	244	.33	140	15.4	28	0	638
	175	Normal	70/40	12 B, C&F Mills	25%	9.7	479	.64	274	16.1	38	0	620
	205	Normal	70/40	16 C&F Mills	35%	8.8	532	.71	305	14.3	33	0	641
3/16/76 34 17A 200 S6	200	Low	70/40	16 C&F Mills	35%	6.3	327	.44	187	15.1	39	0	630

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APPENDIX C

FUEL ANALYSES

Available fuel analysis are presented in this section of the report, on a specific boiler basis where such data exist. It should be pointed out that fuel analyses are not available for the Sewaren Station, Boiler No. 5 (Public Service Electric and Gas Company).

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APPENDIX C
PAGE C-1
TOTAL ANALYSIS

East Kentucky Power Corporation, Inc. - Copper Section, Boiler No. 2

Sample No.	Laboratory No.	Sample Source	Date	Test Conditions	41 9000599 Composite Coal 3/9/77 Baseline	43 9000600 Composite Coal 3/11/77 Baseline	49 9000601 Composite Coal 3/13/77 Low Wt.	60 9000602 Composite Coal 3/15/77 Low Wt.	80 9000603 Composite Coal 3/17/77 Baseline	87 9000604 Composite Coal 3/19/77 Low Wt.	97 9000605 Composite Coal 3/21/77 Low Wt.
Proximate Analysis											
As Received											
Moisture (as received)					7.73	3.61	2.76	4.09	5.12	4.11	3.42
Ash					12.37	12.76	11.26	10.41	12.50	9.92	12.53
Volatile					34.57	35.19	36.62	35.35	32.99	34.72	34.79
Fixed Carbon					45.33	49.43	49.34	50.15	47.00	51.26	48.77
Sulfur					2.60	2.35	3.06	2.13	2.77	2.31	2.49
Nitrogen					11.364	11.163	12.312	12.225	11.743	12.407	12.081
Heating Value					65.8	63.05	63.0	-	64.8	63.8	-
Ultimate Analysis (as Received)											
C					83.61	87.80	88.02	89.68	85.26	78.29	87.89
H					6.42	6.66	6.80	6.71	6.26	6.40	6.47
N					2.40	2.35	2.06	2.13	2.77	2.31	2.49
O					1.39	1.29	1.37	1.43	1.37	1.49	1.47
S					0.13	0.13	0.10	0.09	0.10	0.11	0.11
Ash					7.43	7.43	7.49	7.56	7.09	7.08	8.34
Wt./lb.					12.37	12.76	11.26	10.41	12.50	9.92	12.53
Btu/lb.					11,366	12,165	12,312	12,225	11,743	12,407	12,081
Ash Elements											
SiO ₂					-	-	-	0.34	0.22	0.39	0.32
Al ₂ O ₃					-	-	-	65.61	50.12	45.10	46.08
Fe ₂ O ₃					-	-	-	18.27	19.75	18.14	21.82
CaO					-	-	-	27.88	22.76	28.30	25.32
MgO					-	-	-	1.12	1.02	1.11	1.03
K ₂ O					-	-	-	0.38	0.38	0.34	0.35
Na ₂ O					-	-	-	0.21	0.20	0.20	0.20
Total					-	-	-	2.34	2.36	2.61	2.78
Ash Fusion Temperature, °F											
Softening					2065	2100	2035	198.10	98.60	99.61	98.58
Hardening					2150	2620	2115	2160	2140	2160	2080
Deformation					2150	2620	2115	2160	2140	2160	2080
Fusion					2150	2620	2115	2160	2140	2160	2080
Oxidizing					2150	2620	2115	2160	2140	2160	2080
Reducing					2150	2620	2115	2160	2140	2160	2080
Fluid					2150	2620	2115	2160	2140	2160	2080

APPENDIX C

TABLE C-2

COAL ANALYSIS

Public Service Company of Colorado
Comanche Station, Boiler No. 2

Test No.	16
Laboratory No.	9060466
Sample Source	Composite Coal
Date	6/14/77
Test Conditions	Low NO _x (SASS)

Proximate Analysis

Moisture (as rec'd)	29.77
Ash	5.36
Volatiles	34.40
Fixed Carbon	30.47
Sulfur	0.41
Btu/lb.	7888
Hardgrove Grindability	53.1

Ultimate Analysis-As Received

C - %	48.68
H - %	3.30
S - %	0.41
N - %	0.75
Cl - %	0.03
O - %	11.73
Ash - %	5.36
Btu/lb. - %	7888

Ash Elements

P ₂ O ₅ - %	0.78
SiO ₂ - %	28.65
Fe ₂ O ₃ - %	5.10
Al ₂ O ₃ - %	15.03
TiO ₂ - %	1.19
CaO - %	21.47
MgO - %	3.17
SO ₃ - %	24.90
K ₂ O - %	0.42
Na ₂ O - %	1.26
Total - %	101.97

Ash Fusion Temperature, °F

Reducing - I.D.	2075
- H=W	2125
- H=1/2W	2135
- Fluid	2150
Oxidizing - I.D.	2145
- H=W	2160
- H=1/2W	2170
- Fluid	2180

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APPENDIX C
TABLE C-3
COM. ANALYSIS

Gulf Power Company - Oriskany Station, Miller No. 7									
Test No.	127/128	129	130	132	132A	132B	133	134	135
Laboratory No.	90060608	90060613	90060608	90060605	90060610	90060612	90060612	90060611	90060607
Sample Source	Composite	Composite	Composite	Composite	Coal	Coal	Composite	Coal	Composite
Test Conditions	2/7/78	2/8/78	2/8/78	2/16/78	2/17/78	2/23/78	2/23/78	2/23/78	2/28/78
Test Results	5.59	7.61	6.57	6.66	5.96	5.25	5.25	5.99	5.99
Proximate Analysis									
Moisture (as analyzed)	16.13	15.05	11.75	11.51	10.90	12.39	12.39	12.39	12.39
Volatile	34.08	32.67	33.51	32.63	34.09	31.93	32.66	33.12	33.12
Fixed Carbon	44.20	48.35	48.17	49.20	49.05	50.41	49.44	49.32	49.32
Refuse	5.58	3.84	3.59	3.28	3.05	3.73	3.80	3.08	3.08
Refuse	11.028	10.585	11.670	11.700	11.901	11.813	11.828	11.863	11.863
Ultimate Analysis									
Carbon	60.56	59.02	64.87	64.06	65.58	65.58	65.58	65.58	65.58
Hydrogen	4.76	4.17	4.49	4.57	4.57	4.57	4.57	4.57	4.57
Nitrogen	1.02	1.06	1.17	1.07	1.09	1.18	1.18	1.18	1.18
Oxygen	7.15	9.28	7.48	7.99	8.58	7.50	7.31	8.08	8.08
Ash	16.13	15.05	11.75	11.51	10.90	12.39	12.39	12.39	12.39
Refuse	11.028	10.585	11.670	11.700	11.901	11.813	11.828	11.863	11.863
Ash Elements									
FeO	0.28	0.22	0.17	0.17	0.19	0.31	0.29	0.26	0.26
SiO ₂	42.00	42.00	45.08	47.28	47.85	42.81	42.01	45.70	45.70
Al ₂ O ₃	19.48	19.23	18.01	17.21	16.92	18.49	18.49	18.49	18.49
CaO	0.91	0.91	0.87	0.89	0.93	0.88	0.88	0.91	0.91
MgO	1.72	3.50	5.09	4.13	3.88	3.88	3.88	3.88	3.88
Na ₂ O	0.65	0.95	0.80	0.85	0.80	0.79	0.79	0.80	0.80
K ₂ O	1.89	4.07	5.95	4.90	4.77	4.30	4.16	5.48	5.48
SO ₂	0.44	0.41	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Total	99.64	100.17	101.23	97.45	97.51	99.43	98.55	97.60	97.60
Ash Fusion Temperature, °F									
Reducing	1965	1935	1950	1975	1975	1960	1960	1950	1950
Oxidizing	1990	1960	2010	2035	2035	1990	1990	2050	2050
Fluid	2010	1975	2030	2055	2055	2010	2010	2055	2055
Refuse	2370	2370	2370	2370	2370	2370	2370	2370	2370
Refuse	2370	2370	2370	2370	2370	2370	2370	2370	2370
Refuse	2370	2370	2370	2370	2370	2370	2370	2370	2370
Refuse	2370	2370	2370	2370	2370	2370	2370	2370	2370
Refuse	2370	2370	2370	2370	2370	2370	2370	2370	2370

APPENDIX DANALYTICAL PROCEDURES
FOR
SASS TRAIN SAMPLESSample Preparation

A sample preparation scheme was devised to analyze particulates (by size), condensates, XAD-2 porous polymer resins and impinger solutions for metals, PNA's, and anions.

Sample preparation for the cyclone catches is shown in Figure D-1. The washes from the cyclones were evaporated to dryness and weighed. The mass of material collected by each cyclone and associated washings are detailed in Table 3-34. The dried solid material from the rinses were combined with the appropriate cyclone catches. Portions of the sample were then analyzed for metals and fluoride. Another portion was then analyzed for PNA's and chlorinated organics. The solids from each of the three cyclone catches were proportionally combined and extracted for water soluble sulfates and nitrates.

Sample preparation of the condensate samples is illustrated in Figure D-2. The aqueous XAD-2 resin rinses along with the container washings were added to the condensate sample. Analyses were then performed on this sample to determine the metal and anion content.

The XAD-2 porous polymer resin was prepared for PNA and metal analyses as shown in Figure D-3. Water extraction of the XAD-2 resin was done by rinsing the polymer three times with a total of 150 ml deionized-distilled water. This extract was added to the condensate sample. The resin was then extracted with 500 ml of Burdick and Jackson pentane in a pre-extracted soxhlet thimble. A portion of the organic extract was analyzed for PNA's by the GC/UV procedure described in a later section. A total extractable organochloride analysis was also done on a portion of the pentane extract. A portion of the XAD-2, which was not extracted, was acid digested and analyzed for metals by INAA and for Cd, Ni, Be, and Pb by AAS.

Preparations of the impinger solutions and the coal samples were straightforward with Figures D-4 and D-5 showing the analyses performed.

Sample Analysis

There were three main types of analyses performed on the SASS train samples. They are: metals, PNA's, and anions. Table 3-30 of the text summarizes the specific tests which were requested for the various samples. The analytical techniques used are given in Table 3-31. The following description elaborates on this table giving the details of the methods used.

METALS: All of the different types of samples collected were analyzed for their metal content. Since the EPA protocol suggested survey

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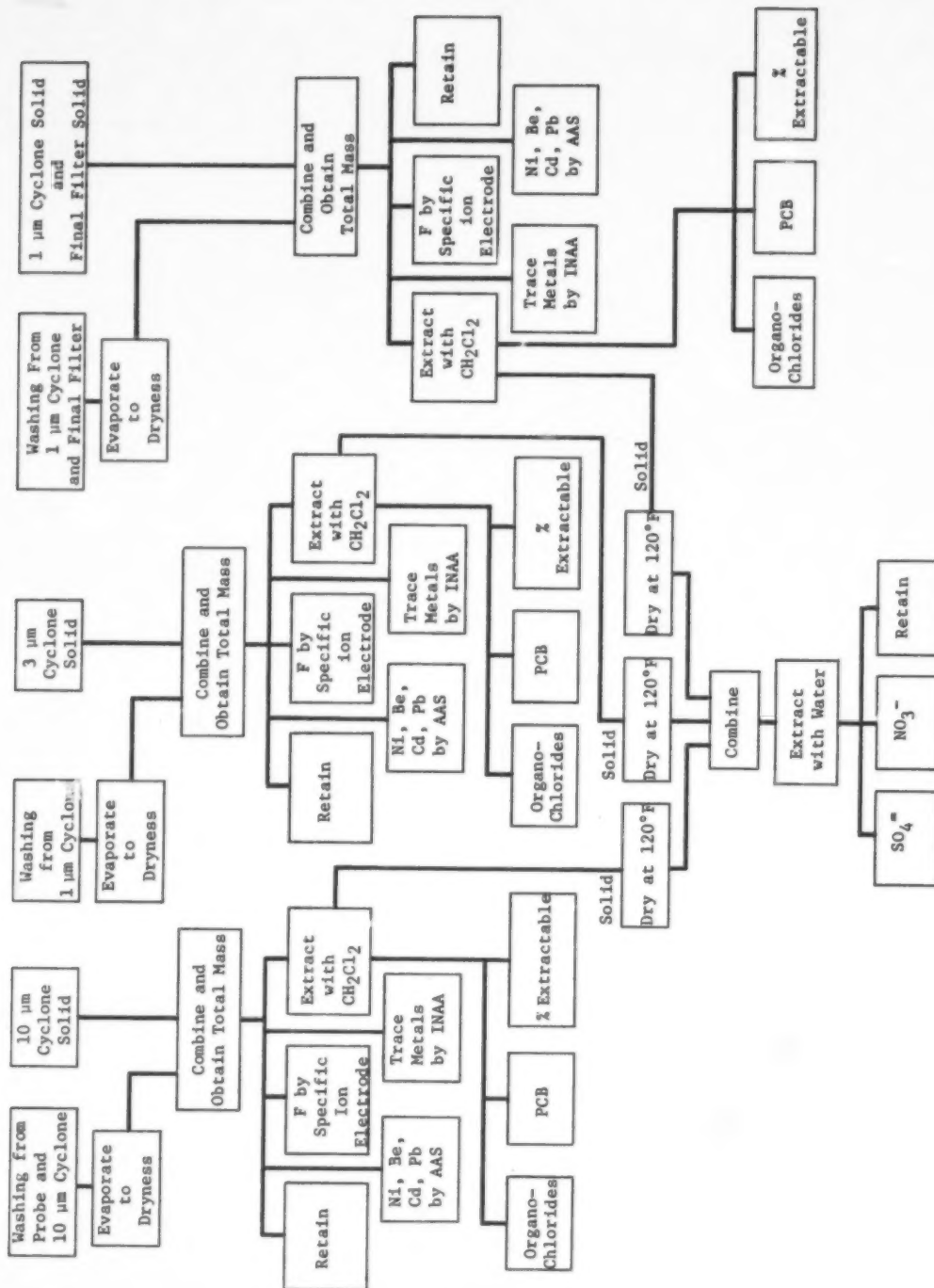


Figure D-1. Preparation of Particulate Samples.

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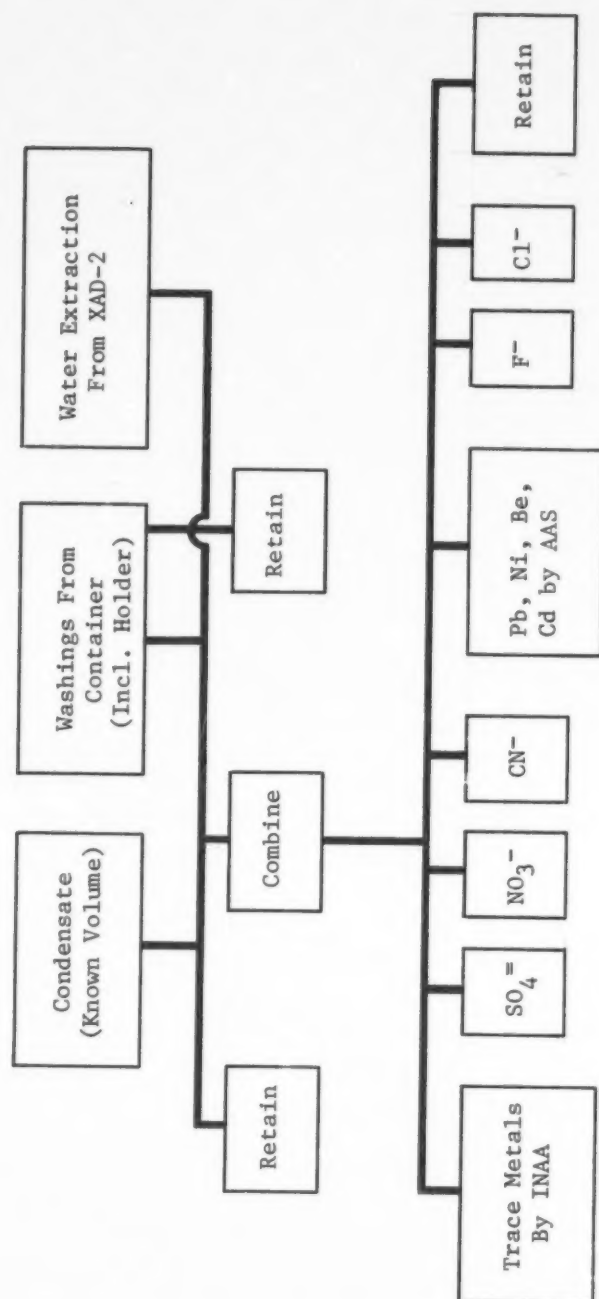


Figure D-2. Preparation of Condensates.

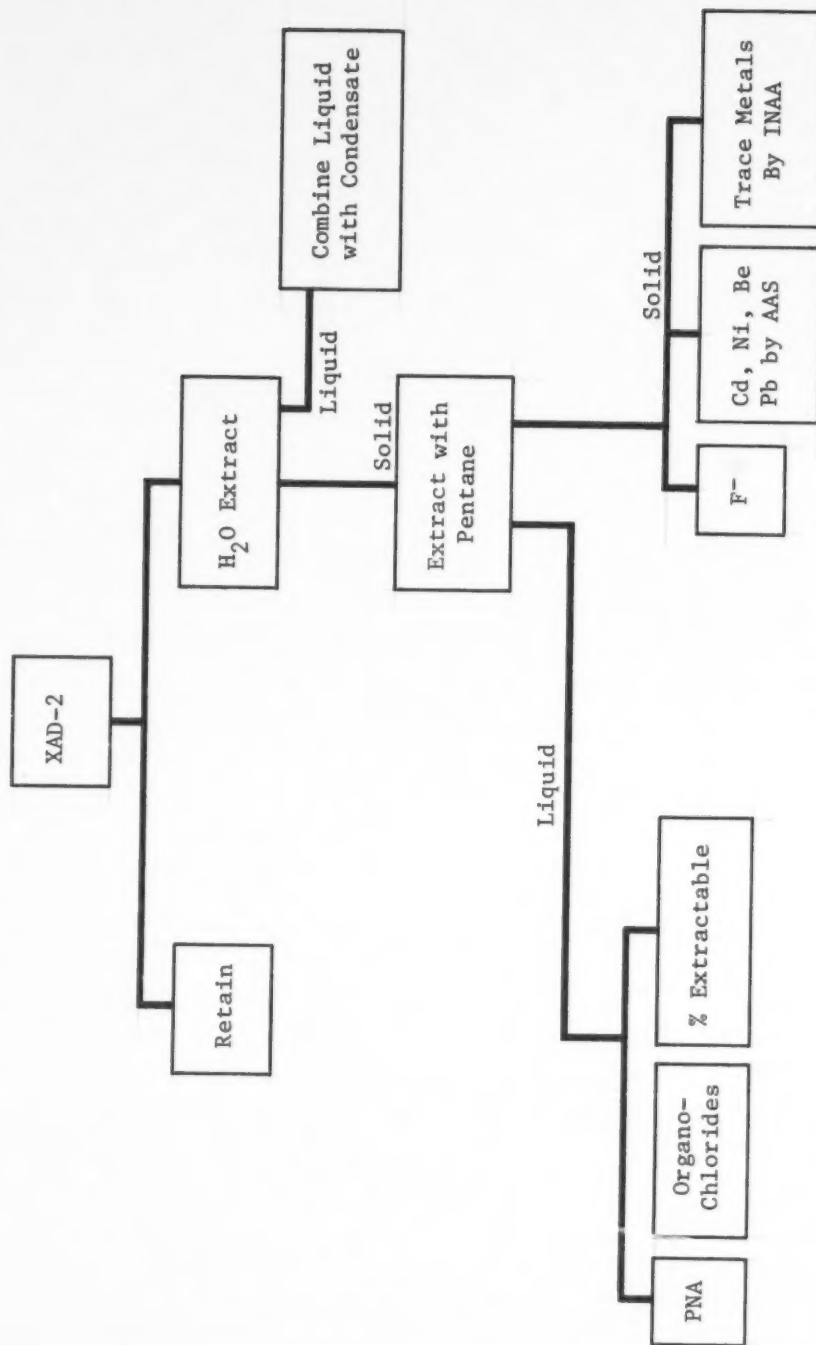
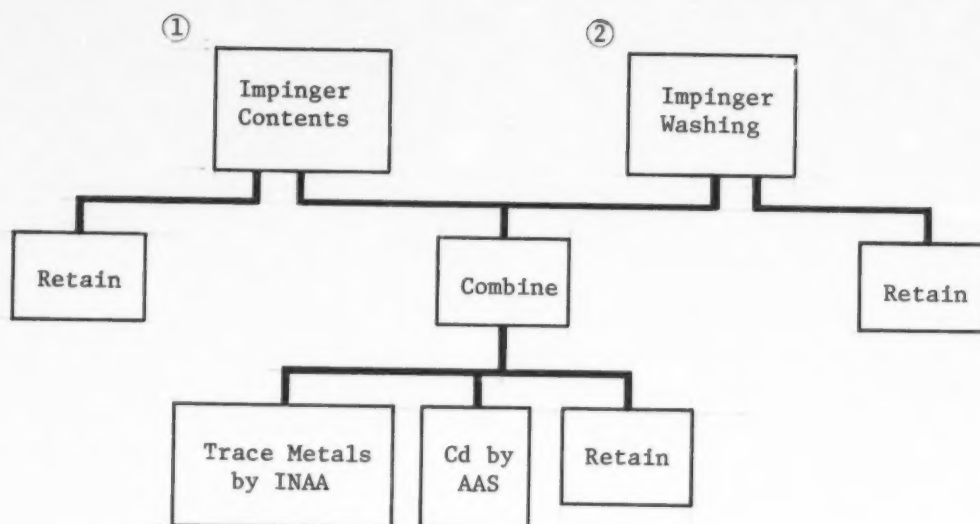


Figure D-3. Preparation of XAD-2.



If ① is Impinger #1, then ② is wash from Impingers #1.

If ① is Impingers #2 & #3, then ② is wash from Impingers #2 & #3.

FIGURE D-5

PREPARATION OF THE COAL SAMPLES

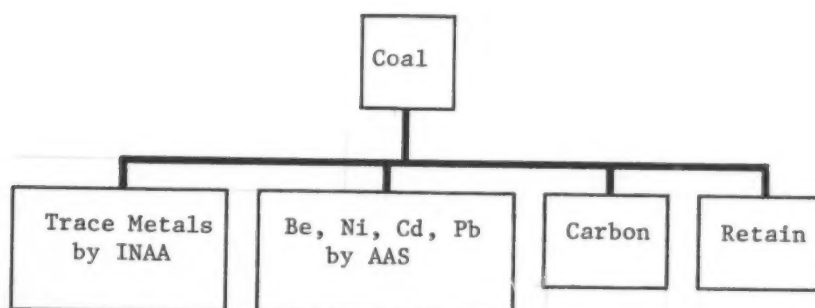


Figure D-4. Preparation of Impinger Samples.

type analyses, neutron activation was the method used to obtain concentration levels for metals either in the solid or aqueous form. All INNA analyses were performed by Virginia Polytechnic Institute (VPI). In order to minimize the possibility of contamination, sample preparation was performed by VPI. Aqueous samples were neutralized with Ultrex grade ammonium hydroxide in order to prevent equipment damage in case of sample container leakage. Most metal data were tabulated based on sample size and air volumes.

Poor results are normally obtained when Be, Cd, Ni, and Pb are analyzed by INAA. Because of this, atomic absorption was chosen as the technique best suited for the analysis of these elements. A few different procedures were attempted prior to selecting the best acid digestion technique.

The first method attempted was the TRW sample preparation procedure. This method was used to prepare NBS coal (SRM 1632) and coal fly ash (SRM 1633) samples for AAS analysis. Typical data are shown in Table D-1. The procedure was tried five times with similar results. High Ni levels were probably due to leaks in the teflon-lined Parr bombs. In addition to the high nickel levels, the large amount of dissolved solids made Cd determinations difficult due to low signal to noise ratios coupled with high background absorption corrections. Sulfation of the sample also appeared to have little effect on the results.

Perchloric acid digestion of the NBS fly ash was attempted but the data listed in Table D-2 show that this approach is unsatisfactory for all metals except Cd.

The third procedure involved the ashing of the sample (sulfated) at 450°C followed by HF and HCL treatment of the ash to affect dissolution. The data obtained on the NBS standards along with other samples using this procedure have been incorporated with other NAA results. A detailed description of this procedure is shown in Appendix E.

PNA's: Samples to be analyzed for PNA's are spiked with carbon-14 labeled benzo(a)anthracene and benzo(a)pyrene internal standards prior to soxhlet extraction. The extracts were then purified by an adapted FDA "wax procedure"² which involves the use of DMSO/H₃PO₄ in selectively concentrating PNA's from interfering compounds. Often it was necessary to further clean the sample by elution through a deactivated Al₂O₃ column in order to further reduce background interferences.

- 1 "Procedures for Process Measurements of Trace Inorganic Materials," EPA Contract #68-02-1393, July 1975.
- 2 Code of Federal Regulations, No. 172.886 Vol. 21, Food and Drug Administration, 1 April 1977, p. 414.
- 3 Pancirov, R. J. and Brown, R. A., Conference on the Prevention and Control of Oil Spills, San Francisco, Ca. (1975) P. 103, Amer. Pet. Inst., Washington, D.C. 20037.

The purified extract was then reduced in volume to approximately 10 μ l. An injection of 5 μ l is then made onto a 6.1 meter SE-30 column (175-300°C, 40min). The PE-900 gas chromatograph is equipped with a splitter on the outlet with 15% for the FID and 85% for trapping in stainless steel tubes. Each GC peak is individually trapped. The material is removed from the traps by cyclohexane elution in an ultrasonic bath. Known aliquots are removed from the fractions containing the carbon-14 PNA compounds for counting.

Identification of each PNA is³ made from the UV absorbance spectrum and the retention time of the GC peaks. The amount of material present in the sample is then calculated from the carbon-14 recovery data, sample size, UV absorbance and absorptivity at the analytical wavelength. Since each PNA has a different sensitivity to UV radiation, the detection limits will reflect these variations. Differences in sampling volumes and variations in the carbon-14 PNA recoveries explain the shift in detection limits between samples.

ANIONS: Particulate samples were analyzed for fluoride by Battelle Laboratories of Columbus, Ohio. The procedure involved fusion by the samples with sodium carbonate, sulfuric acid digestion and separation by distillation. The final fluoride determination was made with a D-ION-X ion chromatograph. Initial attempts were made by analyzing samples with an ion selective electrode. However, Battelle felt that the fluoride may have been complexed resulting in erroneously low values.

Cyanide analysis was done by ASTM method No. 2036. Concentration of the cyanide was accomplished by distillation with visible absorbance at 620 nm used for the final measurement. Liquid samples were analyzed for fluoride directly with an ion selective electrode while chloride analysis was done by titration with silver nitrate.

Particulate samples were extracted with water to remove water soluble sulfates and nitrates. The sulfate analysis was accomplished by first passing the extract through a Dowex 50 WXB cation exchange resin to remove cations. The sulfate was then titrated with a barium perchlorate solution using a 0.2% thorin solution as an indicator.

The nitrate samples were first treated with sulfuric acid to destroy any nitrites and then adding this solution to cooled sulfuric acid along with a portion of 2,6-dimethylphenol solution. Absorbance from 320-330 nm are then compared to a calibration curve to determine the amount of nitrate present. This method was a modification of one previously published.⁴

⁴ Hartley, A. M. and Asai, R. I., Anal. Chem. 35, 1207 (1963).

ORGANOCHLORIDES: Microcoulometry was the technique used to determine the amount of extractable organic chloride present in the particulate and XAD-2 resin samples for test No. 16. The XAD-2 resin was extracted with pentane in a soxhlet apparatus. The particulate samples were methylene chloride extracted. These extracts were solvent exchanged five times with pentane prior to analysis. Although a blank methylene chloride sample was also solvent exchanged with pentane and analyzed it is possible that residual amounts of methylene chloride present in the sample could cause erroneously high chloride values.

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TABLE D-1

Be, Cd, Pb and Ni Data on
NBS Coal and Coal Fly Ash Samples Using TRW Procedure

<u>Sample</u>	<u>----- Wt% Ni -----</u>			
	<u>Be</u>	<u>Cd</u>	<u>Pb</u>	<u>Ni</u>
Coal (Sulfated)	1.2 (1.5)*	1.6 (0.2)	38 (30)	24 (15)
Fly Ash (Sulfated)	22 (12)	0.9 (1.45)	38 (70)	113 (98)
Fly Ash (Unsulfated)	12	3	133	125

*All data in parenthesis are NBS certified values.

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TABLE D-2
PERCHLORIC ACID DIGESTION OF NBS FLY ASH

<u>Sample</u>	<u>-----Wt% Ni-----</u>			
	<u>Be</u>	<u>Cd</u>	<u>Pb</u>	<u>Ni</u>
Fly Ash (Sulfated)	4 (12)*	1.2 (1.45)	22 (70)	56 (98)
Fly Ash (Unsulfated)	6	1.6	43	72

*All data in parenthesis are NBS certified values.

APPENDIX ETHE DETERMINATION OF Be, Cd, Ni,
AND Pb IN COAL AND COAL FLY ASHIntroduction

This procedure is intended for the determination of Be, Cd, Ni, and Pb in coal and coal fly ash materials.

Summary of Method

The sample is muffled at 450°C, treated with HF, remuffled, and the remaining ash dissolved in HCl. The Be, Cd, Ni and Pb are analyzed by flame atomic absorption spectroscopy using the technique of standard additions.

Apparatus

- (1) Atomic Absorption Spectrometer. A Varian (any model) instrument is recommended for the optimum sensitivity. The capabilities of background (non-atomic) correction, air/acetylene and nitrous oxide acetylene flames, and signal readout on a stripchart recorder are recommended.
- (2) Muffle Furnace.
- (3) Platinum Dishes - 40 ml capacity.

Reagents

- (1) Ultrex Sulfuric, Hydrochloric and Hydrofluoric Acids. Available from J. T. Baker Chemical Company.
- (2) Separate Be, Cd, Ni, and Pb Standard Solutions (1000 ppm). Available from the Fischer Scientific Company.

Sample Preparation

- (1) Weigh approximately 0.3 grams of fly ash or 0.6 grams of coal to the nearest 0.1 milligram into a platinum dish.
- (2) Treat the sample with a few drops of concentrated sulfuric acid and take to dryness on a hot plate.
- (3) Muffle the sample for at least 2 hours at 430 to 450°C.

- (4) After the ash has cooled, wet with deionized-distilled water, add 1 ml of concentrated HF, and take to dryness.
- (5) Repeat step (4) with 0.5 ml of HF.
- (6) Muffle at 450°C for ~1 hour to remove the HF.
- (7) After the ash has cooled, wet with water, and add sufficient concentrated HCl to affect dissolution within ~3 hours.
- (8) If insolubles are present, filter the sample through Whatman #42 filter paper, char and muffle the ash at 450°C and repeat steps (5) - (7) above.
- (9) Transfer the digestate to a 50 ml volumetric flask and make to volume with 10% V/V hydrochloric acid/water.

Sample Solution Analysis

- (1) Pipette 20 ml of the sample solution into a cleaned plastic container.
- (2) To the sample aliquot add 20 μ l of a 1000 μ g/ml Pb stock, 10 μ l of a 1000 μ g/ml Ni stock, 10 μ l of a 100 μ g/ml Cd stock, and 20 μ l of a 200 μ g/ml Be stock. This results in the addition of 1.0 μ g/ml Pb, 0.5 μ g/ml Ni, 0.05 μ g/ml Cd, and 0.2 μ g/ml Be.
- (3) Aspirate the sample and sample spike solutions into the flame of an atomic absorption spectrophotometer. Record the absorbance readings with the aid of a strip chart recorder. Use background correction for all sample analyses.

The following is a listing of the recommended instrumental parameters:

<u>Element</u>	<u>(nm)</u>	<u>SBP (nm)</u>	<u>Flame-Stoichiometry</u>	<u>Lamp Current (mA)</u>
Be	234.9	0.5	N ₂ O/C ₂ H ₂ -Reducing	5
Cd	228.8	0.5	Air/C ₂ H ₂ -Oxidizing	3
Ni	232.0	0.2	Air/C ₂ H ₂ -Oxidizing	5
Pb	283.3	0.2	Air/C ₂ H ₂ -Oxidizing	6

- (4) Subtract the background absorbance from the sample and sample plus spike absorbance to obtain the corrected absorbances.
- (5) Calculate the ppm metal using the following equation:

$$\text{ppm M} = \frac{(\text{Metal addn. in g/Ml} \times (\text{corrected sample absorbance}) \times 50)}{(\text{Corrected Sample} + \text{Spike Abs.} - \text{Corrected sample absorbance})}$$

$$(\text{Sample Weight in Grams})$$